

Basin-Centered Gas Systems of the U.S.

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**BASIN-CENTERED GAS SYSTEMS OF THE U.S.
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INTRODUCTION

The USGS is re-evaluating the resource potential of basin-centered gas accumulations in the U.S. because of changing perceptions of the geology of these accumulations, and the availability of new data since the USGS 1995 National Assessment of United States oil and gas resources (Gautier et al., 1996). To attain these objectives, this project used knowledge of basin-centered gas systems and procedures such as stratigraphic analysis, organic geochemistry, modeling of basin thermal dynamics, reservoir characterization, and pressure analysis.

This project proceeded in two phases which had the following objectives:

Phase I (4/1998 through 5/1999): Identify and describe the geologic and geographic distribution of potential basin-centered gas systems, and

Phase II (6/1999 through 11/2000): For selected systems, estimate the location of those basin-centered gas resources that are likely to be produced over the next 30 years.

In Phase I, we characterize thirty-three (33) potential basin-centered gas systems (or accumulations) based on information published in the literature or acquired from internal computerized well and reservoir data files. These newly defined potential accumulations vary from low to high risk and may or may not survive the rigorous geologic scrutiny leading towards full assessment by the USGS. For logistical reasons, not all basins received the level of detail desired or required.

The thirty-three potential accumulations investigated in Phase I are in the list below. For each, we summarize the geologic setting and data favoring the existence of a potential basin-centered gas accumulation.

Anadarko Basin	Mesozoic Rift Basins (eastern U.S.)
Appalachian Basin (Clinton-Medina and older Formations)	Michigan Basin (St. Peter Sandstone)
Arkoma Basin	Mid-Continent Rift
Black Warrior Basin	Paradox Basin (Cane Creek interval)
Central Alaska basins	Park Basins of Colorado
Chuar Group (Precambrian Paradox Basin)	Permian Basin (Abo Formation)
Columbia Basin	Rio Grande Rift (Albuquerque Basin)
Colville Basin, Alaska	Raton Basin
Cook Inlet, Alaska	Sacramento Basin
Denver Basin	Salton Trough, California
Great Basin (Tertiary basins)	San Rafael Swell (Dakota Formation)
Gulf Coast-Austin Chalk	Santa Maria Basin (Monterey Formation)
Gulf Coast-Eagle Ford Formation	Snake River downwarp, Idaho
Gulf Coast-Travis Peak/Cotton Valley Formations	Sweetgrass Arch (central Montana)
Hanna Basin	Wasatch Plateau
Hornbrook Basin/Modoc Plateau	Western Washington (Willamette-Puget
Los Angeles Basin (deep)	Sound Trough)

PHASE I

In Phase I we divided the thirty-three (33) basins or areas into two categories: **High Potential Accumulations**, or those we believe have high potential for development in the next 30 years, and **Other Potential Accumulations**, those that have some potential, but are not as likely to be developed within the next 30 years. Note that well-known and explored basin-centered accumulations (such as the Green River basin, the San Juan basin, the Piceance basin, and the Uinta basin) are not addressed in this report. We grouped the 33 areas using some of the following considerations:

- (1) the amount of data available for an area, and our level of confidence in the data;
- (2) the magnitude or size of the potential resource;
- (3) the geologic and economic risk (e.g., depth, remoteness);
- (4) geographic distribution;
- (5) the estimated 30-year impact of the potential accumulation; and
- (6) the relationship to the USGS 1995 national oil and gas assessment (Have our perceptions about an area changed?).

List of high potential accumulations:

Anadarko Basin
Columbia Basin
Cook Inlet, Alaska
Gulf Coast-Travis Peak/Cotton Valley Formations
Hanna Basin
Michigan Basin (St. Peter Sandstone)
Paradox Basin (Cane Creek interval)
Permian Basin (Abo Formation)
Raton Basin
Rio Grande Rift
Sacramento Basin

List of other potential accumulations:

Appalachian Basin (Clinton-Medina and older Formations)	Los Angeles Basin (deep)
Arkoma Basin	Mesozoic Rift basins (eastern U.S.)
Black Warrior Basin	Mid-Continent Rift
Central Alaska basins	Park Basins of Colorado
Chuar Group (Precambrian Paradox Basin)	Salton Trough
Colville Basin, Alaska	San Rafael Swell (Dakota Formation)
Denver Basin	Santa Maria Basin (Monterey Formation)
Great Basin (Tertiary basins)	Snake River downwarp
Gulf Coast-Austin Chalk	Sweetgrass Arch (central Montana)
Gulf Coast-Eagle Ford Formation	Wasatch Plateau
Hornbrook Basin/Modoc Plateau	Western Washington (Willamette-Puget Sound Trough)

PHASE II

In Phase II we made a much more comprehensive analysis of seven of the eleven high potential areas from Phase I determined to contain resources that will be available in a 30-year period. These areas include the following:

Anadarko Basin
Columbia Basin
Gulf Coast-Travis Peak/Cotton Valley (two reports presented separately)
Michigan Basin (St. Peter Sandstone)
Raton Basin
Rio Grande Rift (Albuquerque Basin)
Sacramento Basin

Extensive research and analysis on each of the seven areas resulted in interpretive reports that will be released as separate chapters in U.S.G.S. E-Bulletin Series 2184. The U.S. Geological Survey's publication policy states that interpretive research cannot be published as an Open-File Report; therefore, the eight reports, now in press, will be published as Electronic Bulletins and will be available via the Internet at:

<http://greenwood.cr.usgs.gov/bulletin.html>

The titles and abstracts for each of the eight bulletin chapters follow in **Appendix I: Phase II Abstracts**.

BASIN-CENTERED/CONTINUOUS-TYPE ACCUMULATIONS

Basin-centered or continuous-type accumulations are large single fields having spatial dimensions equal to or exceeding those of conventional plays. They cannot be represented in terms of discrete, countable units delineated by downdip hydrocarbon-water contacts (as are conventional fields). The definition of continuous accumulations is based on geology rather than on government regulations defining low permeability (tight) gas. Continuous accumulations are identified by their occurrence downdip from water-saturated rocks, lack of obvious trap or seal, relatively low matrix permeability, abnormal (either high or low) pressures, large in-place hydrocarbon volumes, and low recovery factors ([Schmoker, 1995](#)). There may be a period of normal pressuring during the transition between over- and underpressuring. This period can occur when a basin experiences uplift and erosion, causing basin cooling.

The U.S. Geological Survey 1995 National Petroleum Assessment treated continuous plays as a separate category, and play assessment used a specialized methodology ([Schmoker, 1995](#)). Continuous plays are geologically diverse and include the following categories: coal-bed gas, some biogenic gas occurrences, fractured gas shales, and basin-centered natural gas accumulations. Only continuous-type basin-centered gas plays comprise significant future undiscovered resources in deep sedimentary basins.

Assessment of continuous plays is based on the concept that an accumulation can be regarded as a collection of hydrocarbon-bearing cells. In the play, cells represent spatial subdivisions defined by the drainage area of wells. Cells may be productive, nonproductive, or untested. Geologic risk, expressed as play probability, is assigned to each play. The number of untested cells in a play, and the fraction of untested cells expected to become productive (success ratio) are estimated, and a probability distribution is defined for estimated ultimate recoveries (EURs) for those cells expected to become productive. The combination of play probability, success ratio, number of untested cells, and EUR probability distribution yields potential undiscovered resources for each play. Refer to [Schmoker \(1995\)](#) for a detailed discussion of continuous-type plays and their assessment.

In 1995 the USGS defined 61 continuous-type plays with oil and gas reservoirs in sandstones, shales, chinks, and coals. Of the 61 identified plays, 47 were assessed, of which 34 were gas plays. Estimates of technically recoverable gas resources from continuous-type sandstones, shales, and chinks range from 219 Tcf (95th fractile) to 417 Tcf (5th fractile), with a mean estimate of 308 Tcf. Continuous-type accumulations were not assessed or identified in many areas or regions of the U.S.

Four categories of continuous-type accumulations can be identified with respect to new data and perceptions since the USGS 1995 National Petroleum Assessment:

- (1) Continuous-type plays that were correctly identified as such, assessed in 1995, but need to be updated because of new data;
- (2) Continuous-type plays that may have been identified incorrectly as conventional plays and assessed as such in 1995;
- (3) Continuous-type plays that were identified as such in 1995, but not assessed because of a lack of data; and
- (4) New continuous-type plays that were not identified in 1995.

In detail, basin-centered gas accumulations have the following characteristics:

- (1) They are geographically large and cover from 10s to 100s of square miles in areal extent, often occupying the central deeper parts of sedimentary basins;
- (2) They lack downdip water contacts, and hydrocarbons are not held in place by gas floating above water;
- (3) Reservoirs are abnormally pressured, either under- or overpressured;

- (4) The pressuring phase of the reservoir is maintained by gas;
- (5) Water production is usually low or absent;
- (6) Most reservoir permeability is low, generally less than 0.1 md;
- (7) Reservoirs may be overlain by normally pressured rock;
- (8) Reservoirs contain primarily thermogenic gas, although some shallow basin-centered reservoirs containing gas of biologic origin occur in somewhat different geologic environments;
- (9) Source rocks are in close proximity to reservoir rocks;
- (10) Structural and stratigraphic traps are less important; compartments may exist and can generally form an array of accumulation "sweet spots;"
- (11) Multiple fluid phases contribute to seal development in reservoirs; and
- (12) The tops of many basin-centered accumulations occur within a narrow range of vitrinite reflectance, usually between 0.75 and 0.9 Ro.

Examples of pressure condition variability in gas deposits

A distinction needs to be made between low-permeability (tight) conventional accumulations, which may or may not be abnormally pressured, and continuous basin-center accumulations that are, by definition, abnormally pressured. If only limited geologic and production data are available, erroneous interpretations may result. The following examples from the Phase II interpretive reports (in press) illustrate the high variability in pressure conditions in gas deposits that may or may not be basin-centered accumulations.

Hanna Basin, Wyoming (a basin-centered continuous-type accumulation with both over- and underpressured compartments)

A geologic and production data set based on 29 deep wells in the Hanna basin supports the presence of a hypothetical (no known production) basin-center gas play. The Hanna is a small, deep Laramide pull-apart basin located in south-central Wyoming.

Data interpretations suggest that both over- and underpressured compartments exist ([Wilson et al., in press](#)). A gas-charged overpressured interval may exist within the Cretaceous Mowry, Frontier and Niobrara Formations at depths below 10,000 ft along the southern and western margins of the basin. Overpressuring may also occur near the basin center within the Steele Shale and lower Mesaverde Group section at depths below 18,000 to 20,000 ft. This overpressured zone is likely to be relatively small (probably 20 to 25 mi in diameter) and is probably depleted of gas near major basement reverse faults and outcrops where gas may have escaped.

A zone of subnormal pressure also may exist below a shallow water-saturated, normally pressured zone, and above the central zone of overpressure. Subnormal pressures may occur in the center of the Hanna basin at depths ranging from 10,000 to 25,000 feet based on indirect evidence that includes lost-circulation zones. On the south side of the basin, where the top of the sub-normally pressured zone is believed to cut across stratigraphic boundaries, tests of the Niobrara Formation in three wells showed some gas and oil recovery with very low shut-in pressures.

Appalachian Basin (Clinton-Medina and Older Formations) (normal conventional accumulations and continuous-type underpressured basin-centered accumulations)

In the Appalachian basin, oil and gas trapped in Lower Silurian sandstone reservoirs define a regional hydrocarbon accumulation covering large areas of Ohio, Pennsylvania, New York, and Ontario, Canada (Ryder and Zagorski, 2000). Major reservoirs consist of Clinton and Medina Sandstones in Ohio, and Crimsby and Whirlpool Sandstones of the Medina Group in Pennsylvania and New York. These Lower Silurian sandstones were deposited as a regional clastic wedge in a foreland basin setting during the late phase of the Taconic orogeny. Using Rocky Mountain examples as a guide, the eastern gas-bearing part of the Lower Silurian regional accumulation is recognized as a basin-center gas accumulation, whereas the western part is recognized as a conventional accumulation.

In Ohio and northwestern Pennsylvania, the boundary between accumulation types has been placed at the -3,500 ft subsea structural contour on the top of the Clinton Sandstone (Ryder and Zagorski, 2000). East of this northeast-trending boundary, reservoirs are underpressured, gas-charged, and contain no producible water. Reservoirs west of the boundary, in the conventional part of the accumulation, have mobile formation water and are normally pressured. Here, the updip pinchout of the Lower Silurian clastic wedge stratigraphically traps conventional reservoirs. In the eastern basin-center gas accumulation, reservoirs are tight (less than 0.1 md), and have high irreducible water saturations and abnormally low formation pressures.

Gulf Coast Basin–Cotton Valley Group (normal to overpressured conventional accumulations)

In 1995 the USGS assessed two conventional gas plays and one continuous basin-center gas play (Cotton Valley Blanket Sandstones Gas play) in Cretaceous/Jurassic Cotton Valley sandstones of the onshore northern Gulf Coast basin. Re-evaluation of geologic and production data on hundreds of wells suggests that all of these plays are conventional, and that a continuous basin-center gas accumulation does not exist in Cotton Valley sandstones (Bartberger et al., in press).

Using reservoir properties and gas-production characteristics, Bartberger and others (in press) identified two Cotton Valley sandstone trends: 1) transgressive blanket sandstones across northern Louisiana have relatively high porosity and permeability and do not require fracture stimulation to produce gas at commercial rates; and 2) south of this trend and extending westward into east Texas, massive sandstones of the Cotton Valley exhibit low porosity and permeability and do require fracture stimulation. Pressure gradients throughout most of both trends are normal.

Two factors indicate that the fields in this trend are conventional: 1) the presence of gas-water contacts in at least seven fields across the blanket-sandstone trend, and 2) the relatively high permeabilities and high gas-production rates occurring without fracture stimulation. Within the tight massive-sandstone trend, however, permeability is sufficiently low that gas-water transition zones are vertically extensive and gas-water contacts are poorly defined. With increasing depth through these transition zones, gas saturation decreases and water saturation increases; eventually, gas saturations may become sufficiently low that, in terms of cumulative production, wells become non-commercial. The interpreted presence of gas-water contacts within the tight, massive Cotton Valley sandstone trend suggests that accumulations in this trend are also conventional, and that a basin-center gas accumulation does not exist within the Cotton Valley Sandstone in the northern Gulf Basin.

PROJECT ORGANIZATION

TASKS:

Phase I (April 1998 through March 1999)

The USGS shall conduct a National inventory of known basin-centered gas systems, define new potential systems, rank them according to levels of geologic certainty, further delineate their geologic and geographic characteristics, and produce a map showing their distribution throughout the U.S.

Task No. 1 *April 1998 through March 1999*

Conduct a National inventory of known basin-centered gas systems and produce a map showing geographic location, and supporting documentation of their stratigraphic location and geologic characteristics.

Task No. 2 *April 1998 through March 1999*

Re-examine basins and other areas throughout the U.S. that were previously defined as conventional accumulations, and determine if they might have been mis-classified. If it is determined that these basins or areas exhibit characteristics that could be consistent with those of basin-centered gas systems, maps of their location and supporting geologic documentation will be provided.

Task No. 3 *October 1998 through March 1999*

Risk and rank the newly created list of basin-centered gas systems according to levels of geologic certainty.

Phase II (June 1999 through November 2000)

Phase II focuses on defining “sweet spots” (that portion of the basin-centered gas resource that will be available in 30 years) within the seven basin-centered gas systems determined in Phase I (*Sacramento/San Joaquin Basins, Raton Basin, Rio Grande Rift, Anadarko Basin, Travis Peak/Cotton Valley, Columbia Basin/W. Flank of the Cascades, Michigan Basin/St. Peter Sandstone*).

Task No. 4 *June 1999 through November 2000*

Through rigorous geologic analysis, define “sweet spots” within the selected basin-centered gas systems.

Task No. 5 *June 1999 through November 2000*

For the “sweet spots”, make judgments and recommendations as to the 30-year availability of the gas resource.

Task No. 6 *June 1999 through November 2000*

Prepare a final report that documents the Phase I and Phase II activities. The final report shall include a digital map showing all defined basin-centered gas systems for the U.S., documentation of their geologic characteristics, identification of selected potential sweet spots, and judgments and recommendations as to the social relevance of the resource (availability over a 30-year time frame).

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Anadarko Basin
Appalachian Basin (Clinton-Medina and older Formations)
Arkoma Basin
Central Alaska basins
Columbia Basin
Cook Inlet, Alaska
Denver Basin
Gulf Coast-Travis Peak/Cotton Valley Formations
Mid-Continent Rift
Raton Basin
Western Washington (Willamette-Puget Sound Trough)

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San Rafael Swell (Dakota Formation)

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Permian Basin (Abo Formation)

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Park Basins of Colorado

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Colville Basin, Alaska
Great Basin (Tertiary basins)
Hornbrook Basin/Modoc Plateau
Snake River downwarp

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Gulf Coast-Austin Chalk
Gulf Coast-Eagle Ford Formation
Sacramento Basin
Sweetgrass Arch (central Montana)

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Chuar Group (Precambrian Paradox Basin)
Michigan Basin (St. Peter Sandstone)
Paradox Basin (Cane Creek interval)

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Rio Grande Rift (Albuquerque Basin)
Wasatch Plateau

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Central Alaska basins
Gulf Coast-Travis Peak/Cotton Valley Formations

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Appalachian Basin (Clinton-Medina and older Formations)
Black Warrior Basin
Hanna Basin
Los Angeles Basin (deep)
Mesozoic Rift Basins (eastern U.S.)

M.S. Wilson

Salton Trough, California

ANADARKO BASIN

GEOLOGIC SETTING

The Anadarko Basin extends from western Oklahoma to the eastern part of the Texas panhandle. [Figure 1](#) shows the geomorphic or tectonic features that border the basin: the Amarillo Uplift to the southwest, the Wichita-Criner Uplift to the south, the Arbuckle and Hunton-Pauls Valley Uplift to the southeast, the Central Oklahoma Platform to the east, and the Northern Oklahoma Platform to the north. The Anadarko Basin is asymmetric in profile and deepest along the steep southwestern flank near the Wichita Fault system. Displacement along this fault exceeds 30,000 feet ([Al-Shaieb, et al., 1997a](#)).

One of the deepest basins in the United States, the Anadarko Basin contains over 40,000 feet of Paleozoic sediments. [Figure 2](#) shows a generalized stratigraphic column of the basin. [Hill and Clark \(1980\)](#) have divided the deposits into five sequences: 1) a mid-Cambrian Arbuckle to post-Hunton-orogeny period (of mostly carbonate deposition), with hydrocarbons found mainly in structural traps; 2) Mississippian deposition of carbonates that formed stratigraphic traps for gas; 3) Pennsylvanian deposition of Morrow-Springer series clastic rocks (mostly in the northern shelf areas where the sediments were unaffected by orogenic movements in the southern parts of the basin); 4) post-Morrowan or Late Pennsylvanian deposition of segregated sand lenses; and 5) deposition of lower to middle Permian dolomitized shelf carbonates and Pennsylvanian Granite Wash sediments.

Formation of the Anadarko Basin began during the collision of Gondwana with the southern continental margin of Paleozoic North America. Structural inversion of the core of the southern Oklahoma aulacogen into the Wichita thrust belt caused thrust loading of the region to the north, which subsided and became the Anadarko Basin. Late Pennsylvanian transpression formed numerous thrust-cored, en-echelon anticlines within the southeastern part of the basin that were later eroded and overlain unconformably by Permian carbonates. Subsidence of the basin continued into middle Permian time. The basin has remained quiescent since late Permian time ([Perry, 1989](#)).

HYDROCARBON PRODUCTION

Major hydrocarbon production from the Anadarko basin includes gas and oil from multiple Pennsylvanian reservoirs (Granite Wash, Atoka, Morrow, and Springer Formations). The largest Pennsylvanian Atoka field is the Berlin in Beckham County, Oklahoma, with an estimated ultimate recovery of 362 BCFG at 15,000 ft depth ([Lyday, 1990](#)). Some deep production has occurred from Mississippian through Cambro-Ordovician strata: Washita Creek field in Hemphill County, Texas, from the Cambro-Ordovician at 24,450 ft depth (single well reserves as high as 24 BCFG); and the Knox field (near the southeastern flank of the basin) from the Ordovician Bromide (Simpson) at 15,310 ft depth (single well reserves as high as 6.2 BCFG).

EVIDENCE FOR BASIN-CENTERED GAS

Strong evidence for a basin-centered gas accumulation is present in the form of thermally mature source rocks, widespread production and shows of gas, and overpressuring ([Figure 3](#)) that cuts across stratigraphic boundaries. High pressure gradients occur within the Red Fork and Morrow Sandstones. The Woodford shale forms the base of the pressure cell ([Figure 4](#)); the top of the cell climbs stratigraphically into the basin ([Al-Shaieb et al. \(1990\)](#) termed this regional overpressured cell a “Megacompartiment Complex” or MCC). Vitrinite reflectance values for the Woodford follow this same general trend. The Pennsylvanian Atokan source rocks may exhibit these same maturation trends.

KEY ACCUMULATION PARAMETERS

Identification

Mid-Continent Province, Anadarko Basin, Devonian Woodford through Pennsylvanian Oswego overpressured cell; plays 5812 through 5820 ([Gautier et al., 1996](#))

Geologic Characterization of Accumulation:

- | | |
|---|---|
| a. Source/reservoir | Interval includes Devonian Woodford shale through Pennsylvanian Oswego formation, overpressured Megacompartments Complex (Al-Shaieb et al., 1990, 1997a) |
| b. Total Organic Carbons (TOCs) | Values for the Woodford Shale range to 9%. Atokan values unknown, but assumed to be high (Hester et al., 1990) |
| c. Thermal maturity | Ro 0.5 – 2.0 (values from Woodford shale) (Hester et al., 1990) |
| d. Oil or gas prone | Gas prone |
| e. Overall basin maturity | Most of the basin is mature (Ro values for the Woodford exceed 0.7%) (Hester et al., 1990); overmature in the deepest parts of the basin |
| f. Age and lithologies | Cambrian to Permian; sands, shales, carbonates, and granite wash |
| g. Rock extent/quality | Apparent basin-wide source and reservoir-rock distribution; rocks often become tight in the deeper parts of the basin |
| h. Potential reservoirs | Many producing reservoirs |
| i. Major traps/seals | Woodford Shale, Atokan shales, Cambrian through Devonian shales and carbonates |
| j. Petroleum generation/migration models | Both in-situ generation and long distance migration of gases and oils from shales, carbonates and coaly rocks. The Bakken Shale model of Meissner (1978) for hydrocarbon generation and expulsion applies to evaluation of the Woodford Shale |
| k. Depth ranges | Productive rocks occur at depths greater than 26,000 ft. Overpressure occurs below 10,000 ft (Al-Shaieb et al., 1997a, b) |
| l. Pressure gradients | Range from about 0.28 psi/ft outside the pressure cell to 0.8 psi/ft in the Springer-Morrow section, in the deepest part of the basin (Al-Shaieb et al., 1997a, b). |

**Production and Drilling
Characteristics:**

- a. Important fields/reservoirs** Many fields produce from Cambrian through Permian rocks: Washita Creek field in Hemphill County, Texas, at the west end of the basin (from the Cambro-Ordovician at a depth of 24,450 ft; single well reserves as high as 24 BCFG); Knox field near the southeastern flank of the basin (from Bromide (Simpson) production at 15,310 ft depth; single well reserves as high as 6.2 BCFG) ([Al-Shaieb et al., 1997b](#)); Berlin field in Beckham County, Oklahoma (from the Pennsylvanian Atokan formation; estimated ultimate recovery of 362 BCFG at 15,000 ft depth ([Lyday, 1990](#)))
- b. Cumulative production**

**Economic
Characteristics:**

- a. Inert gas content** Gases are generally high in Btu content and low in total inert gases
- b. Recovery** Recoveries vary depending on permeability, porosity and depth
- c. Pipeline infrastructure** Very good
- d. Exploration maturity relative to other basins**
- e. Sediment consolidation** Most rocks are well indurated
- f. Porosity/completion problems** Shales, tightly cemented sands and other tight (low permeability rocks) have the potential to produce where naturally fractured (many deep Anadarko Basin fields have permeabilities of less than 0.1 md). Water sensitive clays also cause problems.
- g. Permeability** Ranges from less than 0.08 up to 6,000 md.
- h. Porosity** Highly variable.

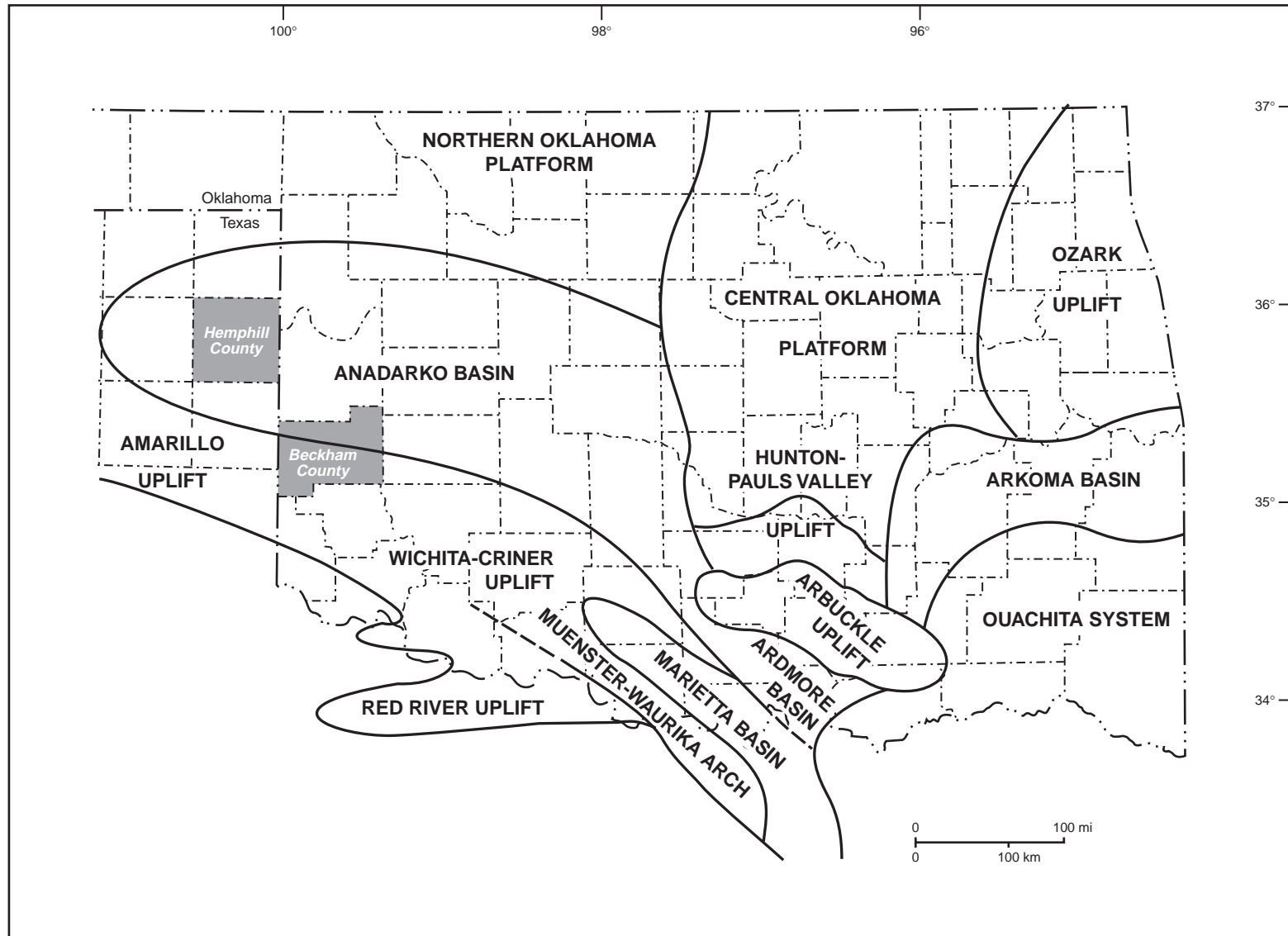


Figure 1. Tectonic map showing location of the Anadarko basin and the major structural features of Oklahoma. After [Arbenz \(1956\)](#), [Al-Shaieb and Shelton \(1977\)](#), and [Al-Shaieb et al. \(1997a,b\)](#).

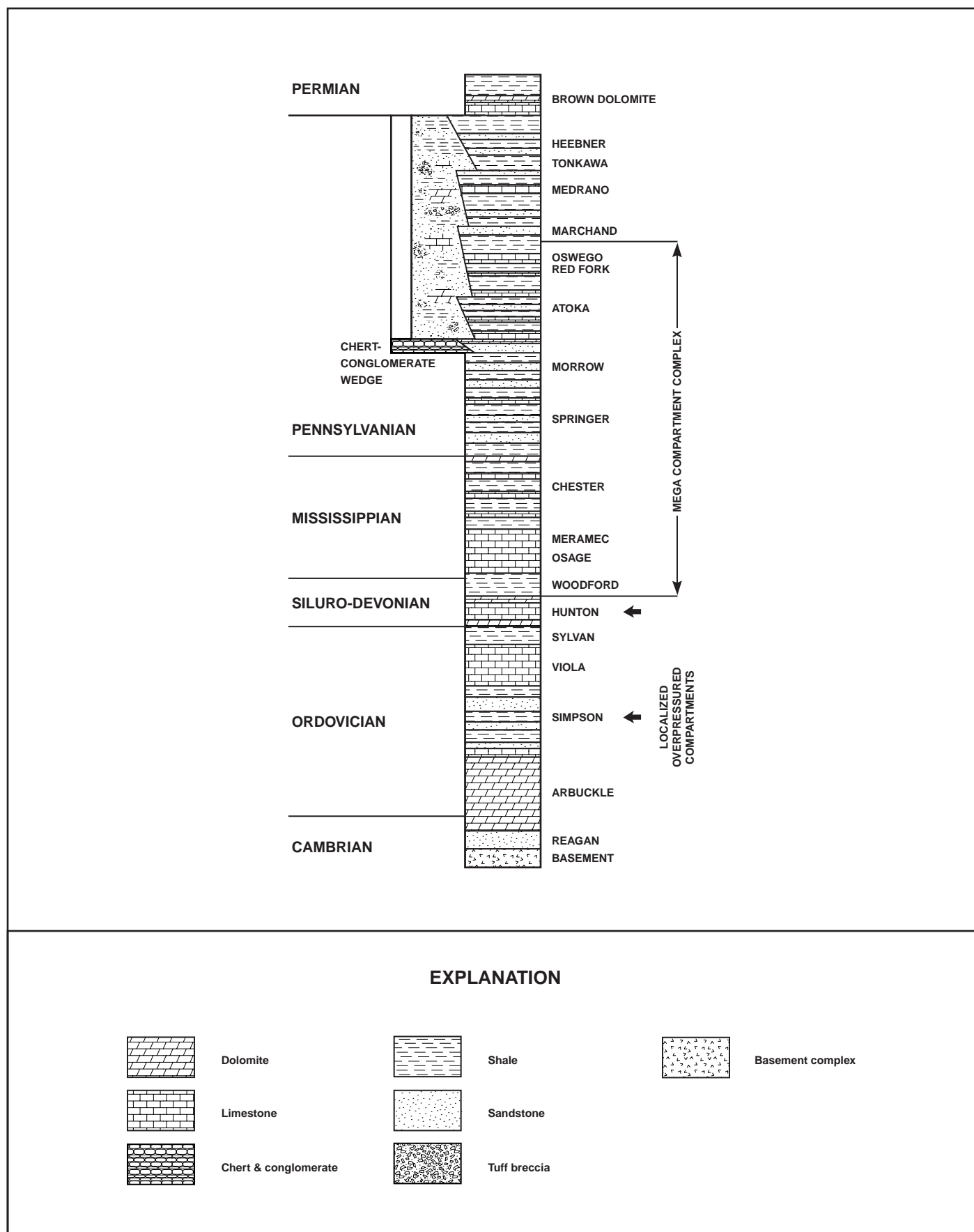
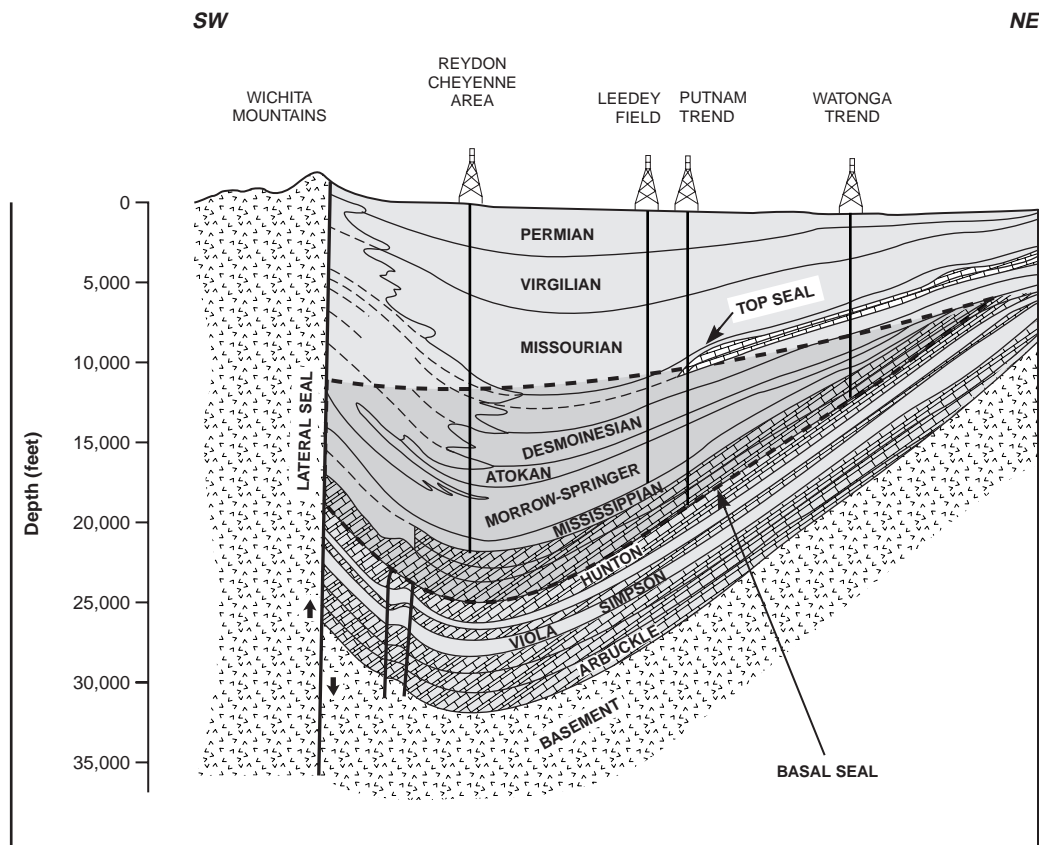


Figure 2. Generalized stratigraphic column of the Anadarko basin showing the intervals contained within the Mega Compartment Complex and the stratigraphic position of two localized overpressured compartments outside the Mega Compartment Complex. After [Evans \(1979\)](#) and [Al-Shaieb et al. \(1997a\)](#).



EXPLANATION

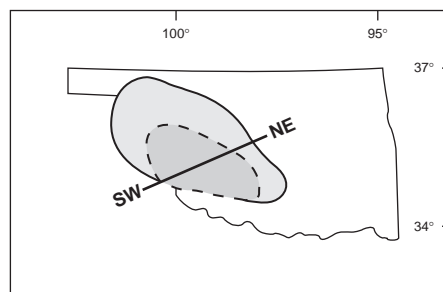
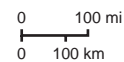
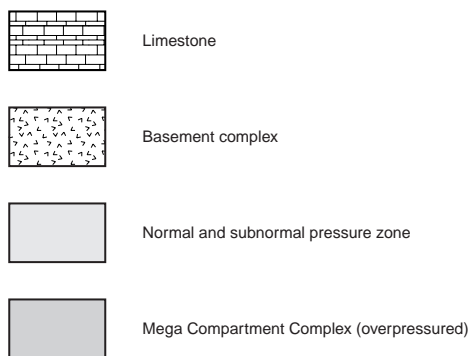


Figure 3. Generalized cross section of the Anadarko basin showing the spatial position of the Mega Compartment Complex within the basin. Geopressures within the Complex are maintained by top, lateral, and basal seals. After Al-Shaieb et al. (1997a,b).

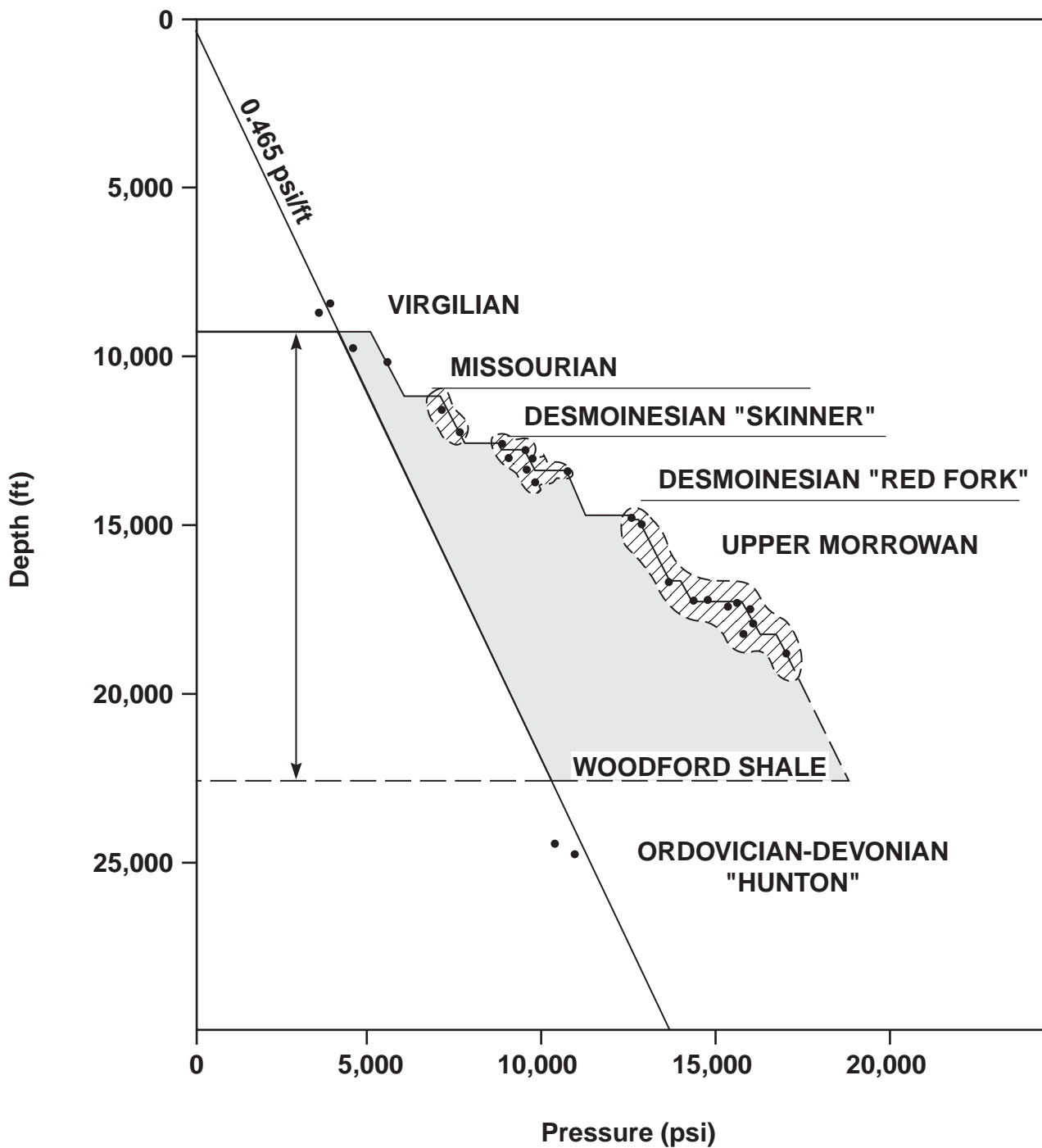


Figure 4. Graphical representation of a pressure-depth profile illustrating the deviation of pressure gradients that define the Mega Compartment Complex in the Red Fork and Morrow intervals. The 0.465 psi/ft slope is the "normal" gradient. This pressure-depth profile represents the Reydon-Cheyenne area in western Oklahoma. After [Al-Shaieb et al. \(1990; 1997b\)](#).

APPALACHIAN BASIN (CLINTON-MEDINA AND OLDER FORMATIONS)

GEOLOGIC SETTING

The Appalachian basin extends southwestward from the Adirondack Mountains in New York to central Alabama. [Figure 5](#) includes the area's location. Structural boundaries include the Cincinnati arch on the west (in western Ohio and Kentucky), and the Allegheny Front on the east (in West Virginia and Pennsylvania). The basin is about 900 miles long and 300 miles wide and includes at least 100 million surface acres ([Roth, 1964](#)).

The Appalachian basin originated as a sedimentary trough on the Precambrian surface that was later covered by Cambrian seas. Deposition of great masses of marine and continental sediments occurred throughout the Paleozoic Era. Carbonate and siliclastic tongues extended basinward from opposite margins synchronously in response to sea level drops. The interplay of eustatic sea-level drop and local tectonic uplift resulted in stratigraphic sequences bounded by widespread unconformities ([Brett et al., 1990](#)). [Figure 6](#) shows correlation of the stratigraphy across the basin. Three major orogenic events affected the basin: the Taconic Orogeny (Late Ordovician), the Acadian Orogeny (Late Devonian), and the Allegheny Orogeny (Late Permian).

The geotectonic history of the basin includes the following stages:

- 1) Precambrian: metamorphic and igneous rocks of the Grenville deformation form a basement under the Appalachian Foreland.
- 2) Early and Middle Cambrian: offset of the basement surface associated with the formation of the Iapetus Ocean during Late Precambrian and Early Cambrian ([Schumaker, 1996](#)).
- 3) Upper Cambrian-Middle Ordovician: relative crustal stability and the formation of a broad carbonate shelf. In the Middle Ordovician, a Foreland basin develops from compression of the passive, carbonate-dominated continental margin during collision with an island arc system (Taconic Orogeny). Thick turbidite sequences record the early phases of the orogeny.
- 4) Late Ordovician (Ashgillian): waning of the main Taconic pulse, and deposition of the Bald Eagle-Oswego sandstone wedge and the Juniata-Queenston red bed sequences.
- 5) Late Ordovician to Early Silurian: tectonic rejuvenation of the Taconic Front. In New York State, evidence for a late Taconic pulse lies in the regionally extensive, low-angle unconformity at the Ordovician-Silurian boundary (Cherokee Unconformity).
- 6) Early Silurian (Cherokee Unconformity) and Late Silurian (Salinic Unconformity): eastward subsidence of the Appalachian Foreland Basin, which coincides with tectonic quiescence and thrust-load relaxation. A thick Early Silurian clastic wedge results from this subsidence. Westward migration in the foreland basin occurred during the Middle Silurian, depositing finer-grained strata; increased tectonism and onset of the Salinic Disturbance may have caused this migration. A small-scale unconformity at the Siluro-Devonian boundary may represent the latest Silurian tectonic activity ([Brett et al., 1990](#)).
- 7) Devonian-Late Permian: The Acadian (Devonian) and Allegheny orogenies (Late Permian) correlate to the collision of the North American plate with other continental plates, eventually creating Pangaea at the end of the Paleozoic ([Schumaker, 1996](#)). During the Allegheny (Appalachian) Orogeny, tremendous thrust pulses from the east and southeast intensely folded and faulted the rocks in the eastern area. The deformation becomes gradually less intense westward. The Ridge and Valley province shows the greatest folding of rocks. The Allegheny Orogeny primarily determined the present day geologic pattern dividing the area into two main parts—the Plateau province, and the Ridge and Valley province ([Roth, 1964](#)).

HYDROCARBON PRODUCTION

The Appalachian basin has the longest history of oil and gas production in the United States. Since Drake's Titusville discovery well in 1859, oil and gas has been continuously produced in the basin. Although opportunities for oil and gas still exist (Petzet, 1991), new field discoveries are rare, and the Appalachian basin has been considered a mature petroleum province as most of the significant plays have been already discovered and developed.

Conventional Plays: Production from Late Cambrian to Late Ordovician rocks is considered conventional:

- (1) The Upper Ordovician Queenston Formation produces gas from sandstones and sandy facies trapped in low-amplitude anticlines and fractures.
- (2) The Middle Ordovician Trenton play produces from fractured micrite in the transition zone between the Trenton limestone and the overlying Utica Shale (Ryder et al., 1995).
- (3) The Middle Ordovician St. Peter sandstone produces from structural traps.
- (4) The Late Cambrian-Late Ordovician Knox Dolomite produces from structural and stratigraphic traps.
- (5) The Cambrian pre-Knox Group (Conasauga Fm., Rome Fm., and Mt. Simon Sandstone) is extensive and underlies the productive "Clinton"/Medina play area. This play has had limited production and may still have potential for future gas production, including basin-centered gas. The section has been sparsely drilled, and thick untested intervals remain in parts of the Rome trough and other areas. Production from pre-Knox rocks has been limited to scattered wells in Kentucky, West Virginia, and Ontario, Canada. The area underlying the Clinton/Medina gas play is considered a low-risk area and has estimated recoverable gas resources of 460 BCF (Harris and Baranoski, 1996).

Unconventional Plays: The oldest producing gas plays in the basin are Upper Devonian black shales and sandstones. These plays include conventional to unconventional continuous-type accumulations. Milici (1996a, 1996b) noted the black shales serve both as source rocks and as reservoirs for gas. Production to date has yielded about 3.0 TCF, and estimates for recoverable reserves reach about 20 TCF (Charpentier et al., 1993).

Basin-centered gas plays: The Lower Silurian "Clinton" sands/Medina Group sandstones gas play is under development in New York, Pennsylvania and Ohio (Figure 5). Development of this basin-centered gas play has expanded since the early 1970s. Ryder (1996) estimated the Appalachian basin to have about 61 trillion (TCF) recoverable gas within Paleozoic sandstones and shales. An estimated 30 TCF may reside in basin-centered gas accumulations in the Lower Silurian "Clinton"/Medina sandstones. Cumulative gas production per well is relatively low. This play appears attractive for four reasons: the overall success rate approaches 90%; the drilling and development costs remain low; there is low water production (and hence, low disposal costs); and the proximity to population centers provides a market for the gas. To maximize gas recovery, operators drill closely spaced (40 acre) wells and horizontal/directional wells. Hydraulic fracturing techniques improved production success from low permeability sandstone reservoirs.

Ryder (1996) defined four continuous-type gas plays (6728-6731) in the "Clinton"/Medina sandstones interval, flanked by two conventional plays that also have potential for continuous-type gas (6732, Clinton-Medina Sandstone Oil/Gas; and 6727, Tuscarora Sandstone Gas). Figure 5 shows locations of basin-centered gas accumulations. Play 6728 (Clinton/Medina Gas High Potential) has the best production potential and covers 16,901 square miles. Source rocks for these plays include Middle to Upper Devonian black shales, and Middle Ordovician Utica and Antes Shales.

The depositional sequence of the "Clinton"/Medina sandstones include the basal Whirlpool Sandstone and Medina Group, which unconformably overlie the Upper Ordovician Queenston Shale. These units represent transgressive shoreface deposits with a lowermost braided fluvial component. The lower part of the "Clinton" sands are shoreface deposits. These sandstones constitute parts of progradational parasequences that successively overlap one another toward the northwest, pinch out seaward into the offshore marine Cabot Head Shale, and then appear to downlap across the underlying transgressive systems. [Ryder et al. \(1996\)](#) interprets the named sandstones in the Cabot Head Shale to be part of a progradational stacked-parasequence. Limestones within the Cabot Head appear to be offshore carbonates separated by inner shelf mudrocks ([Keighin, 1998](#)). These limestones are regionally extensive, but do have pinchouts and thickness changes in the intervening shale beds ([Ryder et al., 1996](#)).

EVIDENCE FOR BASIN-CENTERED GAS

While productive Cambrian and Ordovician reservoirs apparently are conventional gas plays, and Devonian shales and sandstones harbor conventional to unconventional continuous-type accumulations, a basin-centered hydrocarbon accumulation may exist in the "Clinton"/Medina sandstones, especially in play 6728 (Clinton/Medina Gas High Potential) ([Ryder et al., 1996](#); [Ryder, 1996, 1998](#); [Wandrey et al., 1997](#)):

- (1) Regionally extensive sandstones with a thick zone of gas saturation reside in the thicker, more deeply buried part of this foreland basin. Sandstone thickness ranges from 120 to 210 ft, and average net thickness is 25 ft; sandstone-to-shale ratios range from 0.6 to 1.0.
- (2) Gas fields are coalesced, and a high percentage of wells have production or gas shows.
- (3) Reservoirs have low porosity and permeability; porosity ranges from 3 to 11% (averaging 5%). Permeability ranges from 0.2 to 0.6 mD (generally averaging less than 0.01 mD).
- (4) Formation pressures are abnormally low with a gradient ranging from 0.25 to 0.35 psi/ft. In the Tuscarora Sandstone Gas (play 6727), there is evidence for overpressuring with a gradient ranging between 0.50-0.60 psi/ft.
- (5) Structural traps are few.
- (6) A gas-water contact is absent.
- (7) Sandstones with higher water saturations are updip of the gas accumulation.
- (8) Water yields are low; reservoir water saturation is less than 9 to 13 BW/MMCFG.
- (9) Reservoir temperatures are high—at least 125° F (52° C).

KEY ACCUMULATION PARAMETERS

Identification

Eastern U.S. Appalachian basin. Play: Paleozoic Era - Late Cambrian and Ordovician sandstones and shales; Lower Silurian "Clinton" and Medina Group sandstones, and the equivalent Tuscarora Sandstone

Geologic Characterization of Accumulation:

- a. Source/reservoir** The underlying Middle Ordovician Utica shale is the probable hydrocarbon source in the "Clinton"/Medina Group sandstones
- b. Total Organic Carbons (TOCs)** Range from 3.0%-4.0% (Middle Ordovician Utica Shale, Trenton Limestone, Black River Limestone, and Wells Creek Formation); from 0.05% to 0.59% in the pre-Knox ([Harris and Baranoski, 1996](#)).
- c. Thermal maturity** Kerogen: 50% type II and 50% Type III; Vit Ref Equivalent (VRE): 0.75-3.0; Conodont Alteration Index (CAI): 1.5-4.0; Tmax: 440-550. Ordovician strata in the study area are mature for both oil and gas generation ([Wandrey et al., 1997](#); [Ryder et al., 1996](#)).
- d. Oil or gas prone** Both oil and gas prone; vitrinite reflectance suggests the majority of the area is in the window of significant gas generation.
- e. Overall basin maturity** Considered mature
- f. Age and lithologies** Cambrian-Ordovician (pre "Clinton"/Medina); Lower Silurian "Clinton"/Medina Group sandstones and the equivalent Tuscarora Sandstone
- g. Rock extent/quality** Basin-wide source and reservoir-rock distribution. Porosity reduction commonly results from secondary silica cementation; porosity often enhanced by dissolution of calcite cement, feldspars, corrosion of silica cement and by natural fracturing. About half the total resource of the Basin (approximately 30 TCF) is estimated to reside in basin-centered gas accumulations.
- h. Potential reservoirs** "Clinton" sandstones; Medina Group sandstones; Tuscarora Sandstone
- i. Major traps/seals** Cabot Head Shale (Medina Group), Rochester Shale ("Clinton" sands)
- j. Petroleum generation/migration models** Clinton/Medina" - Hydrocarbon source: Utica Shale (Middle Ordovician), gas migration occurred vertically (1000 ft to 1400 ft) via fractures. Organic carbon content data indicates good generative potential for the Middle Ordovician Utica Shale, Trenton Limestone, Black River Limestone, and Wells Creek Formation. Each of these units may have locally sourced basin-centered gas potential; limited generative potential exists in the pre-Knox.

k. Depth ranges pre-Clinton/Medina 6000 to 11,500 ft in eastern OH; Clinton/Medina in eastern OH and NW PA from 4,000 to 6,300 ft; SW PA as much as 10,000 ft; NY 1,000 to 4,000 ft; and southern OH and eastern KY 2,000 to 3,000 ft ([Wandrey et al, 1997](#); [Ryder et al, 1996](#)).

l. Pressure gradients pre-Clinton/Medina - pre-Knox Group underpressured domain: 0.174 psi/ft (Innerkip field, Ontario, Canada); "Clinton"/Medina-(1) underpressured domain: 0.25 to 0.35 psi/ft (verified throughout most of NW PA and adjoining western NY); "Clinton"/Medina-2) overpressured domain: 0.5-0.6 psi/ft, east of the underpressured domain, in the Tuscarora Sandstone, near the Allegheny structural front (in Pennsylvania) ([Ryder, 1996](#)).

Production and Drilling Characteristics:

- a. Important fields/reservoirs** **Pre-"Clinton"/Medina:** Birmingham-Erie Field (Knox Group) sandstone reservoir 100 MMCFG/well; Middle Ordovician fractured carbonates-Harlem gas field 2.1 BCFG; Trenton play Granville consolidated pool 50-100 MMCFG/yr. A few pre-Knox wells have produced gas in the Rome Trough from the Conasauga Group (sands, shales and sandy dolomites), some wells have produced gas with up to 78% nitrogen (uncombustible gas).
- "Clinton"/Medina basin-centered gas:** Lakeshore, Adams/Waterford/Watertown, Athens, Indian Springs Pool of Conneaut field, Kastle pool of Conneaut field, Cooperstown, Oil Creek Pool of Cooperstown field, Kantz Corners, North Jackson/Lordstown, NE Salem, Senecaville, Sharon Deep ([Ryder, 1998](#))
- b. Cumulative production** Most of the basin-centered gas production occurs in Play 6728 (Clinton/Medina Ss Gas-High Potential). Fields tend to merge together into continuous-type accumulations after additional drilling. For example, the three or four Medina fields discovered in the 1960s in Chautauqua County, western New York, have now merged into the giant Lakeshore field, which has an ultimate recovery of 650 billion cf of gas. Assuming 40 acre spacing the median estimated ultimate recovery per well is 70 MMCFG (Play 6728), 50 MMCFG (Play 6729-Clinton/Medina Ss Gas Medium Potential), and high risk/low success ratio for Plays 6730 (Clinton/Medina Ss Gas Medium-Low Potential) and 6731 (Clinton/Medina Ss Gas Low Potential) ([Wandrey et al., 1997](#)). Below are some examples of production data (for the better wells) from the "Clinton" sands in Ohio ([Ryder, 1996](#)).

County (OH) Production	Township	Operator	Cumulative Gas (MMCF) per Lease	Years of Production
Noble.....	Brookfield.....	Kingston Oil Corp.	146,835	1992-1995
Noble.....	Brookfield.....	Everflow Eastern.....	206,736	1990-1995
Noble.....	Brookfield.....	Kingston Oil Corp.	94,548	1993-1995
Trumbull	Fowler	Eastern Petroleum.....	118,622	1987-1995
Trumbull	Fowler	Eastern Petroleum.....	82,148	1985-1994
Trumbull	Fowler	Eastern Petroleum.....	190,776	1984-1995
Noble.....	Center.....	Kingston Oil Corp.	490,911	1985-1995

**Economic
Characteristics:**

- | | |
|---|--|
| a. Inert gas content | In Ohio, average Clinton-Medina nitrogen content is 5.1%, carbon dioxide content is 0.1% (Hugman et al., 1993). In the Rome Trough and adjacent areas, very high inerts in natural gas have been reported from pre-Knox rocks, sometimes rendering the gas non-combustible (up to 78% nitrogen). |
| b. Recovery | Low. Continuous-type accumulations are characterized by low individual well-production rates and small well-drainage area. Directional/horizontal wells are being drilled to reduce the number of well sites. |
| c. Pipeline infrastructure | Very good. There are numerous gas lines in the basin. |
| d. Exploration maturity relative to other basins | Mature |
| e. Sediment consolidation | Consolidation/porosity reduction occurs with depth of burial |
| f. Porosity/completion problems | Tight sands. Improved hydraulic fracturing techniques in recent years resulted in higher gas recoveries. |
| g. Permeability | Pre-Knox=1.0 md (Innerkip field, Oxford Co., Ontario, Canada). |
| h. Porosity | Pre-Knox=3.5 to 22% (Innerkip field, Ontario, Canada). |

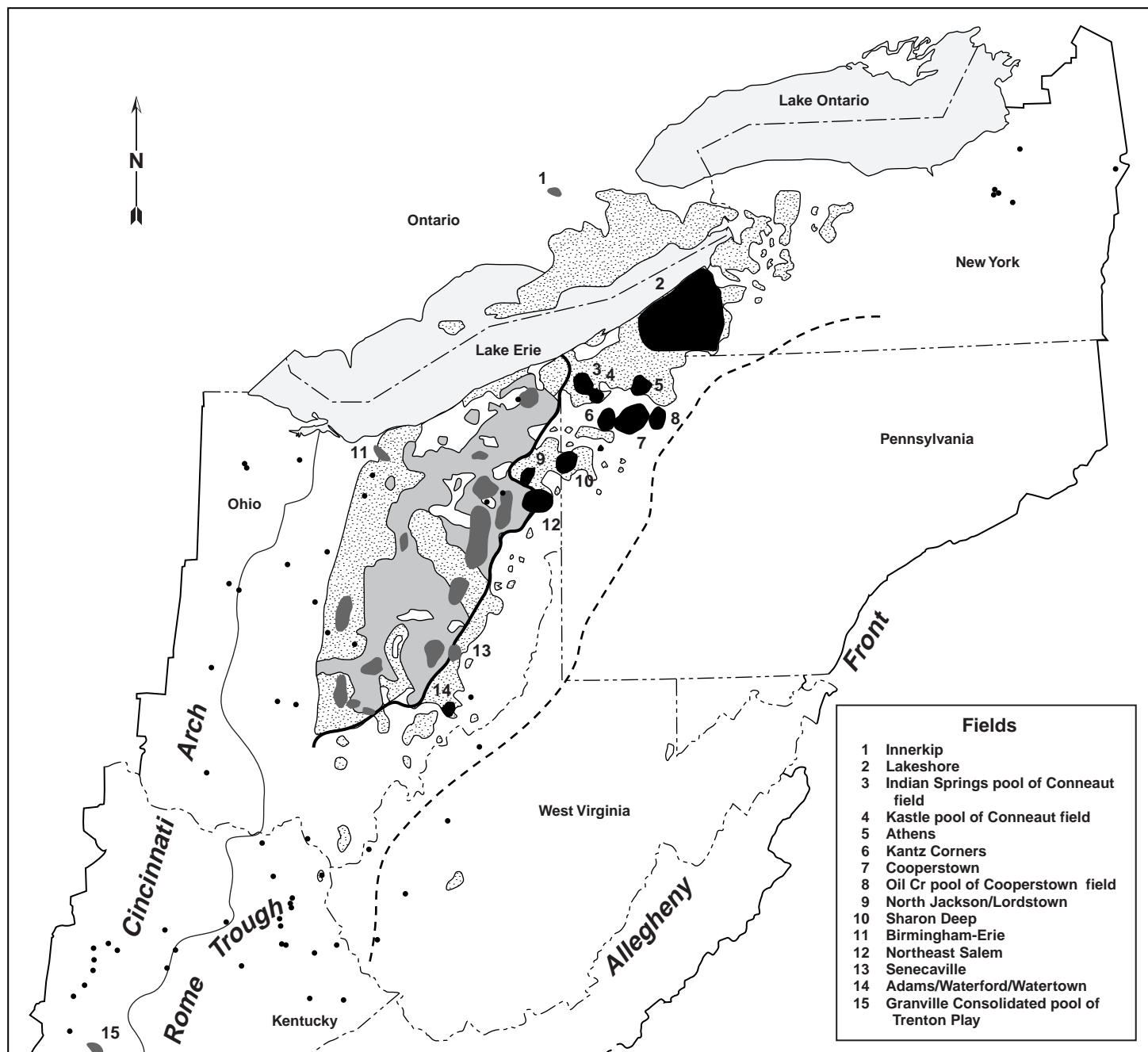


Figure 5. Map showing regional hydrocarbon accumulation in Lower Silurian sandstone reservoirs of the Appalachian basin. Oil and gas shows seen in wells are from pre-Knox units. After [Harris and Baranoski \(1996\)](#), and [Ryder \(1998\)](#).

System	Series	North/West		Central	South	Sequence
Permian	Lower	Dunkard Gr				Alleghenian Flysch
Pennsylvanian	Upper	Monongahela Gr Conemaugh Gr Allegheny Gr				
	Middle	Pottsville Gr				
	Lower	Breathitt Fm Lee Fm				
Mississippian	Upper	Bluestone Fm Princeton Ss Hinton Fm		Pennington Fm		Lower Carboniferous Flysch Molasse Stable Shelf
		Greenbrier Ls		Newman Ls	Bangor Ls Hartselle Ss Monteagle Ls St. Louis Ls Warsaw Ls	
	Lower	Rockwell Mbr Riddleburg Sh Mbr Cussewago Ss Mbr Oswayo Mbr	Price Fm Rockwell Fm	Maccrady Cloyd Cgl Mbr Sunbury Sh Mbr Berea Ss	Price Fm Ft. Payne Fm Grainger Fm Borden Fm	
Devonian	Upper	Dunkirk Sh West Falls Gr Genesee Fm Geneseeo Sh Mbr Moscow Sh Ludlowville Sh Skaneateles Sh Marcellus Sh Onondaga Ls	Ohio Sh Cleveland Sh Mbr Huron Sh Fm Rhinestreet Sh Fm Mahantango Fm Hamilton Gr Delaware Ls Columbus Ls	Catskill Fm Harrell Sh Tully Ls Marcellus Sh Tioga Bentonite Onondaga Ls Huntersville Ch Needmore Sh Oriskany/Ridgeley Ss Helderberg Gr	Hampshire Fm Chemung Brallier unconformity Millboro Sh	Acadian Flysch
	Middle					
	Lower					
Silurian	Upper	Keyser/Bass Islands Salina Gr Lockport Dol	Keyser Fm Tonoloway Fm Wills Creek Fm Bloomsburg Fm Mifflintown Fm Keefer Ss	Williamsport Ss McKenzie Fm		Post Taconic Molasse and Carbonate Shelf
	Lower	Clinton Gr Cabot Head Sh Medina Gr	Shawangunk Fm Massanutten Ss	Rose Hill Fm Tuscarora Fm	Clinch Fm	
Ordovician	Upper	Queenston Fm Oswego Ss	Reedsville Fm	Juniata Fm Bald Eagle Ss Martinsburg Fm	Sequatchie Fm	Taconic Flysch
	Middle	Utica Fm/Antes Fm		Black River /Trenton Ls	Liberty Hall Mbr Stones River /Nashville Gr	
	Lower	"post-Knox" (or pre-Middle Ordovician) unconformity				Mascot Dol Kingsport Fm Chepultepec Dol
Cambrian	Upper	Rose Hill Ss Trempeleau Dol Kerbel Fm	Conococheague Fm	Copper Ridge Dol Maynardville Dol Nolichucky Sh	Knox Gr	Iapetan Rift and Passive Margin
	Middle		Elbrook Fm Honaker Dol	Maryville Ls Rogersville Sh Rutledge Sh Pumpkin Valley Sh	Conasauga Gr Conasauga Sh	
	Lower	Antietam Fm Harpers Fm Weverton-Loudon Fms	Rome Fm/Waynesboro Fm Shady Fm/Tomstown Dol	Erwin Fm Hampton Fm Unicoi Fm	Chilhowee Gr	
Precambrian				Walden Creek Gr Cades Ss Snowbird Gr Mount Rogers Fm	Ocoee Supergroup	

Figure 6. Stratigraphic nomenclature and correlation chart for the Appalachian basin. After Milici (1996b).

ARKOMA BASIN

GEOLOGIC SETTING

The Arkoma Basin follows an east-west trend from northern Arkansas into east-central Oklahoma. [Figure 7](#) shows the structural features that border the area: the Ouachita Mountains on the south, the Seminole Arch and the Arbuckle Uplift on the west, and the Ozark Uplift on the north. Tertiary sediments of the Mississippi Embayment cover the eastern part of the basin. [Figure 8](#) shows the basin is asymmetric in profile.

Compressional structures characterize the southern part of the basin, while normal faulting occurs in the northern part. Development occurred from Cambrian to early Pennsylvanian time. Prior to basin development, the area was a carbonate shelf ([Horn and Curtis, 1996](#)). Subsurface folds and thrust faults formed during the late stages of foreland basin development. During the Late Pennsylvanian sediments completely filled the basin ([Horn and Curtis, 1996](#)).

Structural styles influence hydrocarbon production in the Arkoma basin. Blind imbricate thrust faults dominate the northern Arkansas gas fairway and central basin; these thrusts ramp over normal fault blocks at depths above 5000 feet. Gas reservoirs occur below the thrust faults at depths of 5000 to 10,000 feet.

Seismic and well data reveal a southward thickening package of Carboniferous flysch ([Figure 8](#)) overlying thin Paleozoic shelf strata in western Arkansas. Total sediment thickness reaches an estimated 46,000 feet in the southern Ouachita mountains. Deposition of at least 39,000 feet of flysch occurred north of the Ouachita mountain front ([Lillie et al., 1983](#)).

North of the Ouachita mountains, the Cambro-Ordovician Arbuckle carbonates accumulated in a marine-shelf environment ([Gromer, 1981](#)). Rapid subsidence in the Ouachita basin during Devonian-Mississippian time led to deposition of the Arkansas Novaculite. Deposition of the Mississippian Stanley shale Group, the Pennsylvanian Jackfork Group, the Johns Valley Formation, and the Atoka Formation occurred ([Figure 9](#)) as the Arkoma basin continued to subside. The Atoka Fm includes 20,000 feet of shale, sandstone and coal beds. Flysch sedimentation continued until mid-Pennsylvanian time, when northward thrusting displaced the geosyncline ([Gromer, 1981](#)). A collision between an island arc and the North American plate produced the Ouachita fold belt ([Wickham, et al., 1976](#)).

HYDROCARBON PRODUCTION

Natural gas was first produced in 1901 at a depth of 2,000 feet from Pennsylvanian sandstones in Sebastian County, Arkansas. The greatest exploration activity occurred along the northern part of the basin in Arkansas and Oklahoma. Most major fields were discovered within the first 30 years of industry activity ([Horn and Curtis, 1996](#)). In 1930, gas production was established from the Atokan Spiro sandstone at a depth of 6300 feet. Wilburton field, the Arkoma basin's second largest field, was discovered in 1929 with production from Upper Atokan sandstones at 2500 feet. The Spiro sandstone was tested in 1960 and soon became the main producing zone. Except for Wilburton and Red Oak fields, very few successful wells were drilled below 10,000 feet prior to the 1970's ([Horn and Curtis, 1996](#)).

Production was established from the Spiro sandstone and Arbuckle carbonates in northern Oklahoma and Arkansas during the late 1970s, opening a new fairway for deeper exploration. Production from Arbuckle (Cambro-Ordovician), Viola (Ordovician) and Hunton (Siluro-Devonian) was established at Wilburton field at depths of 13,000 to 14,500 feet in 1988 ([Horn and Curtis, 1996](#)).

Limited shallow oil production occurs from the Stanley group (Mississippian) and fractured Paleozoic cherts (Devonian Arkansas Novaculite) in the southern Ouachitas ([Horn and Curtis, 1996](#)).

EVIDENCE FOR BASIN-CENTERED GAS

The Pennsylvanian Atoka Formation contains coals and shales with gas-prone kerogen. It extends over a wide area and is very thick. Middle Atokan Red Oak sands contain some of the largest gas reserves in the Oklahoma part of the Arkoma basin (Gromer, 1981).

The Devonian Woodford Shale, which contains type II oil prone kerogen, may have generated in excess of 22 billion barrels of oil (Comer and Hinch, 1987). This oil has probably cracked to gas in the deepest parts of the Arkoma basin (Horn and Curtis, 1996). Other source rocks include the Womble (Ordovician), Polk Creek (Ordovician), Sylvan (Ordovician), Woodford (Devonian-Mississippian), Arkansas Novaculite (Devonian-Mississippian) and Caney (Mississippian) shales. Each of these has probably expelled significant hydrocarbons (Horn and Curtis, 1996). Atokan shales are estimated to have generated between 53 and 212 TCFG. A large, relatively untested area in southwestern Arkansas contains thick sequences of interbedded source and reservoir rocks, and may contain large accumulations of gas (Horn and Curtis, 1996).

Figure 10 illustrates profiles of depth vs. vitrinite reflectance (Ro) for undifferentiated wells in Arkansas and Oklahoma. Hendrick (1992) listed the following vitrinite reflectance values for producing zones at Wilburton Field:

Hartshorne Coal	Ro < 1%
Atoka Shale	Ro = 2.3% at 7,500 ft
Atoka Shale	Ro = 2.6% at 9,400 ft
Spiro Sandstone	Ro = 2.7% at 10,000 ft
Spiro Sandstone	Ro = 3.0% at 11,500 ft
Arbuckle Dolomite	Ro = 3.8%

These unusually high vitrinite values at moderate depths indicate a potentially overmature basin. Several thousand feet of sediment may have been eroded from the surface.

The extensive source rocks and high thermal maturity levels in the Arkoma basin indicate that basin-centered gas accumulations may exist which have not yet been identified. Thick Atoka shales probably provide the primary barriers to gas migration. In the lower Paleozoic section, several shale intervals encasing productive carbonate and sandstone reservoirs are thought to be effective seals (Horn and Curtis, 1996).

KEY ACCUMULATION PARAMETERS

Identification

Arkoma Basin Province, Ordovician through Pennsylvanian Desmoinesian

Geologic Characterization of Accumulation:

- | | |
|---|--|
| a. Source/reservoir | Ordovician Womble Shale through Pennsylvanian Desmoinesian shales and coals (Horn and Curtis, 1996); including the Woodford, the Chattanooga, and Atokan Shales |
| b. Total Organic Carbons (TOCs) | Range up to 19.6% in Woodford Shale (Comer and Hinch, 1987) and average 1.1% in Atokan shales (Horn and Curtis, 1996). |
| c. Thermal maturity | R _o ranges from <1.0% for shallow Desmoinesian coals to 3.8% for the deep Arbuckle reservoir at Wilburton field (Horn and Curtis, 1996). R _o ranges from 0.8% to 3.5% at Red Oak field (Houseknecht and McGilvery, 1990) |
| d. Oil or gas prone | Gas prone |
| e. Overall basin maturity | Maturation levels are high. Deep parts of the basin may be overmature. Production exists where apparent overmaturity occurs. |
| f. Age and lithologies | Ordovician to Pennsylvanian, sands, shales, coals and carbonates |
| g. Rock extent/quality | Extensive source and reservoir rock distribution. Reservoir rocks often become tight in the deep parts of the basin. Permeability barriers (seals) are poorly understood and undocumented (Horn and Curtis, 1996) |
| h. Potential reservoirs | Many producing reservoirs |
| i. Major traps/seals | Woodford Shale, Atokan shales, Desmoinesian shales, and Cambrian through Devonian shales and carbonates |
| j. Petroleum generation/migration models | <p>Both in-situ generation and long distance migration of gases and oils from shales, carbonates and coaly rocks. Hydrocarbon generation is probably ongoing with thermal cracking of oils from type II kerogen bearing shales.</p> <p>The Bakken shale model of Meissner (1978), for hydrocarbon generation and expulsion, applies to the Woodford Shale, the Arkansas Novaculite equivalent, and the other type II kerogen source rocks (lower Paleozoic) (Horn and Curtis, 1996).</p> |
| k. Depth ranges | Earliest production in Arkansas was at 2000 ft in depth; productive rocks occur at depths ranging to 14,500 ft at Wilburton field (Horn and Curtis, 1996). Other early production occurred as shallow as 1300 ft (Houseknecht and McGilvery, 1990) |
| l. Pressure gradients | Subnormal pressure gradients (0.3 psi/ft) in shallow Red Oak and Spiro sands at Red Oak Field (Houseknecht and McGilvery, 1990) |

**Production and Drilling
Characteristics:**

- | | |
|---------------------------------------|--|
| a. Important fields/reservoirs | Red Oak Field produces from Pennsylvanian sandstones at depths ranging from 1400 ft to 13,000 ft; Wilburton Field produces from Cambro-Ordovician Arbuckle at depths from 13,000 to 14,500 ft. |
| b. Cumulative production | Red Oak Field has produced 55 Bcfg from the Hartshorne, 700 Bcfg from the Red Oak, and 200 Bcfg from the Spiro sandstones as of 1987. |

**Economic
Characteristics:**

- | | |
|---|--|
| a. Inert gas content | Gases have high btu content and low total inert gas content |
| b. Recovery | Recoveries depend upon permeability, porosity and depth |
| c. Pipeline infrastructure | Very good |
| d. Exploration maturity relative to other basins | Mature |
| e. Sediment consolidation | Most rocks are well indurated |
| f. Porosity/completion problems | Shales, tightly cemented sands and other tight (low permeability) rocks have potential to produce where they are naturally fractured (many deep Arkoma Basin fields have permeabilities of less than 0.1 md). Water sensitive clays also cause problems. Diagenetic permeability barriers are poorly understood. |
| g. Permeability | 0.1-200 md |
| h. Porosity | 5-23% |

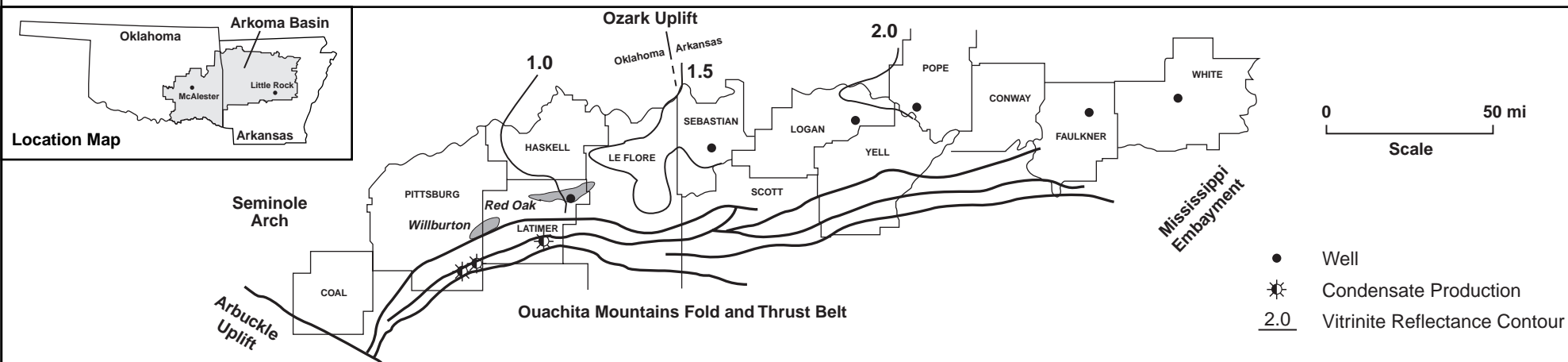
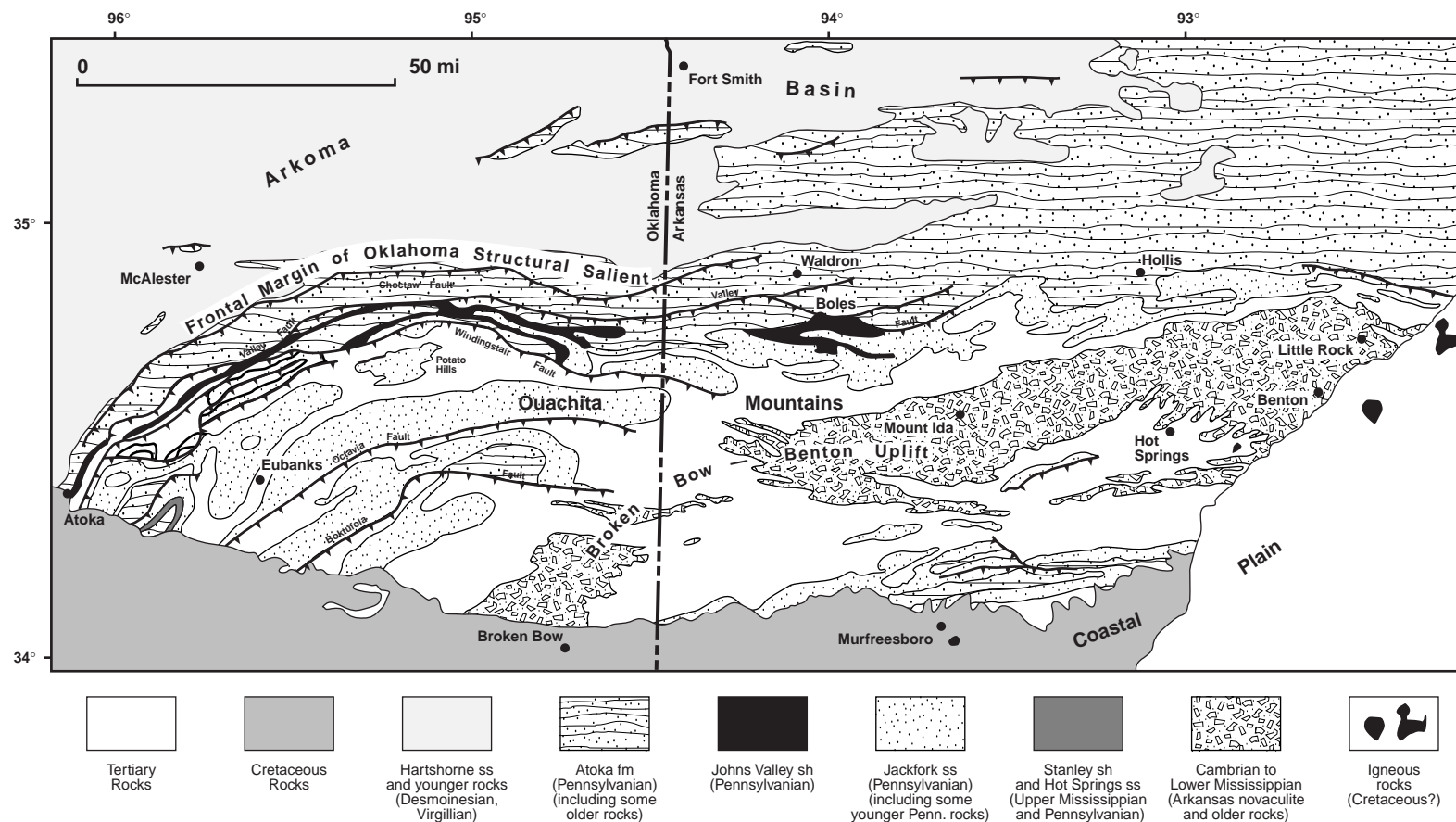


Figure 7: Geologic map of Ouachita Mountains and outline of present-day Arkoma basin. Vitrinite reflectance values derived from Hartshorne coal. After [Gromer \(1981\)](#), and [Horn and Curtis \(1996\)](#).

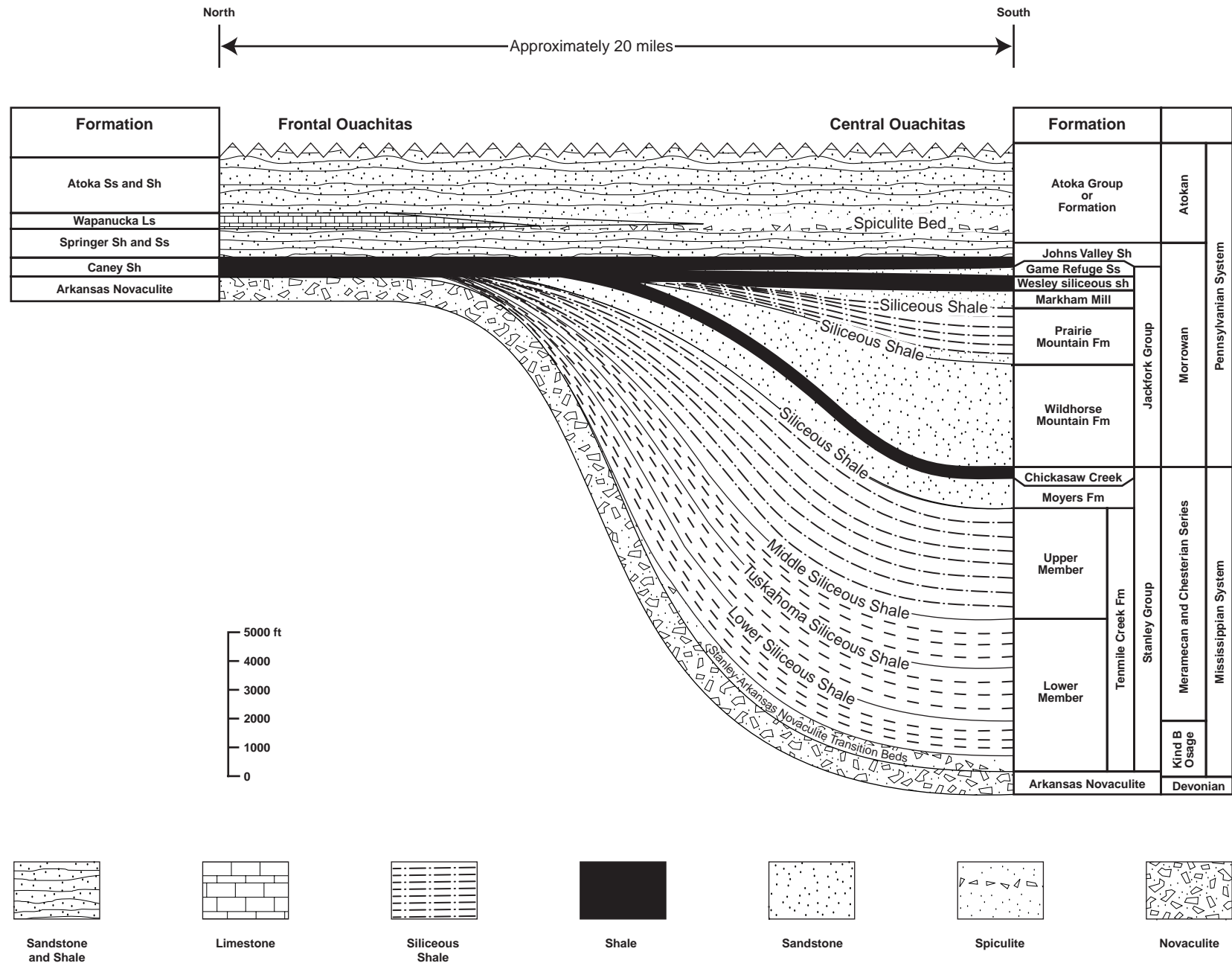


Figure 8. Diagrammatic cross section showing facies changes and correlations of the Late Mississippian and Early Pennsylvanian formations from the frontal Ouachitas to the central Ouachitas, southeastern Oklahoma, with thrust faults eliminated. After [Gromer \(1981\)](#).

System	Series	Arkoma Foreland Basin Facies				Kerogen Type & TOC (%)	Ouachita Mountain Fold and Thrust Belt Facies		Kerogen Type & TOC (%)
		Arkansas		Oklahoma					
Pennsylvanian	Desmoinesian			Marmaton	Calvin	II III <1.0 - 25			II III <1.0 III
				Cabaniss	Senora				
		Boggy Savanna McAlester Hartshorne Ss		Krebs Group	Boggy Savanna McAlester Hartshorne Ss				
	Atokan	Alma Series, Carpenter Basham Upper Hartford Nichols Middle Hartford, Turner Lower Hartford, Morris Tackett Cecil Series Spiro Orr Barton A, Barton B, Barton C		Dirty Creek, Fanshawe Diamond, Red Oak Panola Brazil-Smallwood, Shay Spiro		III 0.5 - 3.4	Jackfork Group	Game Refuge Wesley Markham Mill Prairie Mountain Wildhorse Mountain	III 1.0
		Wapanucka Limestone Kessler Bloyd Brentwood Hale		Wapanucka Limestone Union Valley Cromwell			Stanley Shale	Chickasaw Creek Moyers Ten Mile Creek	
Mississippian	Chesterian	Pitkin Limestone Fayetteville Shale Hindsville Limestone Moorefield Formation		Goddard Shale		III 0.5 - 3.4 II III <1.0 - 14	Arkansas Novaculite		II III <1.0 - 1.4
	Meramecian			Caney Shale					
	Osagean			Welden Limestone					
	Kinderhookian	Boone Formation							
Devonian	Upper and Middle	Chattanooga Shale Sylamore Sandstone		Woodford Shale Misener Sandstone		II III <1.0 - 14			
	Lower	Penters Chert		Salisaw Formation Frisco Formation	Hunton Group				
Silurian	Niagaran			Henryhouse Formation		II III <1.0 - 14	Missouri Mountain Shale		II <1.0 - 1.4
	Alexandrian	Lafferty Limestone St. Clair Limestone Brassfield Limestone	Hunton Group	Chimneyhill Subgroup Petite Oolite	Blaylock Sandstone		II <1.0 - 1.4		
Ordovician	Cincinnatian	Sylvan Cason Shale		Sylvan Shale		II 1.0 - 9.0	Polk Creek Shale		II <1.0 - 1.6
	Champlainian	Fernvale Limestone Kimmswick Limestone, Plattin Limestone, Joachim Dolomite		Welling Formation Viola Springs Formation	Viola Group		Bigfork Chert		II <1.0
		St. Peter Sandstone		Bromide Tulip Creek McIish Oil Creek Joins	Simpson Group		Womble Shale		II <1.0 - 3.4
			Tyner Formation Jasper Limestone King River Ss, Burgen Ss	Everton Formation		I II 1.0 - 9.0	Blakely Sandstone		
	Canadian	Powell Dolomite Cotter Dolomite Jefferson City Dolomite Roubidoux Formation Gasconade-Van Buren Formation	Arbuckle Group	West Spring Creek Kinblade Cool Creek McKenzie Hill Butterfly Dolomite	Arbuckle Group		Mazarn Shale		
				Eminence Dolomite Polosi Dolomite Derby-Doerun-Davis Formation Bonneterre Dolomite Lamontte Sandstone	Singal Mountain Limestone Royer Dolomite Fort Sill Limestone		Timbered Hills Group	Crystal Mountain Sandstone	
Cambrian				Honey Creek Limestone Reagen Sandstone		Collier Shale			
Precambrian		Spavinaw Granite		Granite and Rhyolite			Not Exposed		

Figure 9. Stratigraphic column for the Arkoma foreland basin and Ouachita Mountains, summarizing the range of total organic carbon (TOC by % weight) and kerogen type. After [Montgomery \(1989\)](#), [Johnson and Cardott \(1992\)](#), and [Horn and Curtis \(1996\)](#).

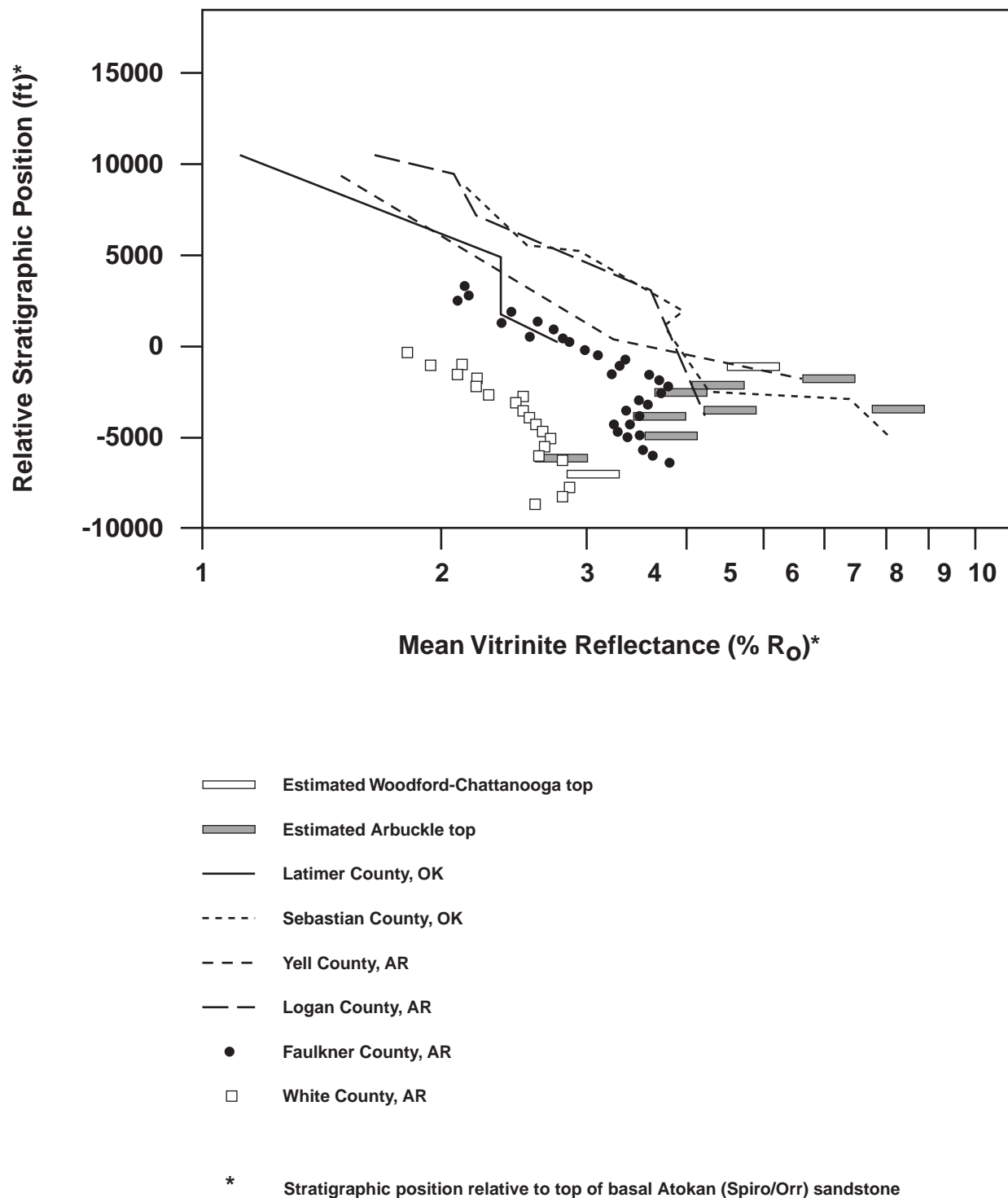


Figure 10. Depth vs. vitrinite reflectance profile for wells in Arkansas and Oklahoma. These profiles use the Spiro Sandstone as a stratigraphic datum and indicate that thermal maturity of eastern Arkansas wells does not follow the inferred west-to-east increase in maturity across the basin. After [Horn and Curtis \(1996\)](#) and [Houseknecht et al. \(1992\)](#).

BLACK WARRIOR BASIN

GEOLOGIC SETTING

The Black Warrior Basin of Alabama and Mississippi is a foreland basin located in the major structural reentrant between the Appalachian fold-and-thrust belt to the southeast and the Ouachita fold-and-thrust belt to the southwest. [Figure 11](#) shows the basin location and its major structural features. The northern margin of the basin is bounded by the Nashville dome. The basin is shaped like a kite with its tail facing south, and has a surface area of about 35,000 square miles. North to south, the basin extends about 190 miles, and the east-west width is about 220 miles. The overall sedimentary section in the province includes rocks of Paleozoic, Mesozoic and Cenozoic age that range in thickness from about 7,000 ft along the northern margin to about 31,000 ft in the depocenter located in eastern Mississippi ([Ryder, 1994](#)).

The geotectonic history of the basin includes 5 stages:

- 1) Late Precambrian-Early Cambrian rift with associated deposition of coarse clastics.
- 2) Middle Cambrian-Mississippian period of stable shelf deposition (7000 ft of shallow water carbonates) occurring on a passive continental margin.
- 3) Late Mississippian (Chester) transitional episode; early stages of continental collision, marine deltaic sedimentation and several major regressive-transgressive cycles.
- 4) Early-Late (?) Pennsylvanian time of maximum basin subsidence and synorogenic deposition related to maturation of the Appalachian-Ouachita thrust belts. Following a brief period of barrier bar development, thick clastic wedges prograded from source areas along the south margin. Abundant coal bed development in north-central portion of the basin.
- 5) Permian-Cretaceous erosion/non-deposition ending with Late Cretaceous marine incursion and deposition into Early Tertiary shallow marine sediments (Mississippi Embayment).

[Figure 12](#) shows a regional cross section of Mississippian strata across northwestern Alabama. The Black Warrior basin was first downwarped in the Late Mississippian-Early Pennsylvanian and then subsequently filled by Pennsylvanian shallow marine and terrestrial clastic material shed from rising highlands along its southern margin. No Permian or early Mesozoic deposits exist in the basin. Indications are that the Black Warrior was uplifted above sea level in Latest Pennsylvanian-Early Mesozoic time ([Montgomery, 1986](#)). Continental break-up during the Mesozoic resulted in the basin becoming downwarped to the southwest and eventually covered by the Mississippi Embayment marine transgressive episode ([Mancini et al., 1983](#)). Most of the basin and its thrust faulted margins are concealed beneath Tertiary and Cretaceous rocks of the Gulf coastal plain and the Mississippi embayment.

HYDROCARBON PRODUCTION

The Black Warrior Basin is very prolific; the Lewis and Carter sandstones (Mississippian Chester Group) are the most productive (Figure 13). The depth to productive horizons ranges from 2,500 to 5,000 ft. Target intervals are generally shallower in Alabama than in Mississippi. The Carter Sandstone and other Mississippian productive intervals extend into deeper basin regions (Bearden and Mancini, 1985). Remarkably high wildcat success rates (50% and more) and the shallow depths of the primary Late Paleozoic reservoir targets (less than 5,000 ft) keep exploration interest high.

There are over 90 individual fields producing oil and gas from two principal productive trends. The northerly trend produces principally from stratigraphic traps. The southern trend produces from structural and combination traps. One of most prolific fields is the unitized North Blowhorn Creek oil field (Lamar County, Alabama), completed in the Carter Sandstone which accounts for nearly 80% of the total oil produced in the entire basin (Montgomery, 1986).

There are multiple gas and gas-condensate reservoirs within the Late Paleozoic clastic units. Eleven individual reservoirs exist in the Mississippian Chester Group. At least 4 clastic units within the Lower Pennsylvanian Pottsville Formation produce gas (Figure 13). The clastic units consist of a series of prograding deltaic environments—delta front, bar finger, and distributary channel sands—separated by transgressive shales. Considerable lateral variability occurs in the reservoirs, and porosities range from 5% to 17%; permeabilities range from .01 to 100 md. Thickness of individual reservoirs range from less than 10 ft to about 50 ft. The total sandstone thickness is less than 1,000 ft.

In addition, the deeper Cambro-Ordovician to Devonian carbonate units also produce in certain locations. To date there have been over 40 deep structural tests (deeper than 10,000 feet) drilled on the Mississippi side of the basin. Many of these tests encountered significant gas shows from Mississippian and Pennsylvanian sandstone sections and from deeper Cambro-Ordovician, Silurian and Devonian rocks (Ericksen, 1993; Henderson, 1991). The lower sections need further exploration, as correlative zones to the west (Hunton and Ellenburger groups) are highly productive (Montgomery, 1986; Duchscherer, 1972; Devery, 1983).

Also, the Alabama part of the Black Warrior basin is one of the main centers of coalbed degasification in the U.S. Lower Pottsville rocks yield gas from depths of less than 2,700 ft, and estimated resources range from 20 to 35 Tcf. To date fields in this area have yielded 0.9 Tcf.

BASIN CENTERED GAS EVIDENCE

Basin center gas potential exists in:

- a. thick clastic wedges off the carbonate platform, in western Alabama and eastern Mississippi, including the least-explored deeper depocenters in Mississippi, and
- b. micritic and finely crystalline limestones and shale/siltstone intervals within Cambro-Ordovician formations.

The basin covers about 1500 square miles. Gas shows are numerous and widespread throughout the basin. Major source rocks are fairly organic, amorphous and herbaceous-prone pro-delta shales with interbedded sandstone. Available geochemical data (including total organic carbon (TOC) thermal alteration index) suggest the basin is mature and the Late Paleozoic shales should be mainly gas prone (Bearden and Mancini, 1985). Henderson (1991) considers the TOCs of the black shales within the Stone River Limestone (Ordovician) favorable for hydrocarbon generation. Pennsylvanian sands in southern Pickens County, Alabama, contain large volumes of in-situ gas; low gas recoveries indicate relatively low permeabilities (R.L. Ericksen, Office of Geology, State of Mississippi, 1999, pers. commun.) and low porosities (S.D. Champlin, Office of Geology, State of Mississippi, 1999, pers. commun.) of the rocks. Pressure gradients recorded to date are normal (Ericksen, 1999, pers. commun.; Champlin, 1999, pers. commun.).

KEY ACCUMULATION PARAMETERS

Identification

Eastern U.S., Black Warrior Basin, Cambrian through Pennsylvanian

Geologic Characterization of Accumulation:

- a. Source/reservoir** Interval includes Mississippian Floyd shale to top of Pennsylvanian Pottsville Formation. Eleven reservoirs exist within the Mississippian Chester Group, and at least 4 clastic reservoirs occur within the Lower Pennsylvanian Pottsville Group. Carter sandstone and other Mississippian productive intervals are now known in deeper basin regions.
- b. Total Organic Carbons (TOCs)** 0.07%-2.36% (Upper Mississippian shales); 2.2% Ordovician Stones River Group (limestone) shales.
- c. Thermal maturity** Mixed including amorphous, herbaceous, woody and coaly material. Alteration state of the kerogen indicates the thermal history is favorable for hydrocarbon generation. Thermal Alteration Index ranges from 2 to 3+, suggesting that the Upper Mississippian is primarily gas prone.
- d. Oil or gas prone** Both oil and gas prone.
- e. Overall basin maturity** Considered mature.
- f. Age and lithologies** Cambrian through Lower Pennsylvanian: black shales of the Stones River Limestone (Ordovician); dark shales of the Conasauga Limestone (Cambrian); Chattanooga (Devonian/Mississippian), Floyd Shale including Lewis sandstone; Packwood Formation including Carter sandstone and Pottsville Formation.
- g. Rock extent/quality** Basin-wide source and reservoir rock distribution
- h. Potential reservoirs**
- i. Major traps/seals** Interbedded Cambro-Ordovician shales; Floyd Shale and interbedded shales of the Packwood and Pottsville Formations
- j. Petroleum generation/migration models**
- k. Depth ranges** From 2500 ft in Alabama to over 10,000 ft in the deeper basin regions in Mississippi.
- l. Pressure gradients**

**Production and Drilling
Characteristics:**

- a. Important fields/reservoirs** The Lewis and Carter intervals are the most highly productive, especially in the north-central part of the basin (Lamar and Fayette counties, Alabama and Monroe, Clay, and Lowndes counties in Mississippi).
- Grove Field, Carter sandstone 67 Bcf; Coal Fire Creek, Carter sandstone 19 Bcf, Lewis sandstone 6.9 Bcf, Fayette sandstone 2.5 Bcf; North Blowhorn Creek oil field—Carter sandstone accounts for nearly 80% of the total oil produced in the entire basin (Montgomery, 1986), Carter sandstone 11.4 Bcf, Millerella 10.5 Bcf; **Sanders Ss**-one well (10,130-10,164 ft), over 12 Bcf in 10 years. Yellow Creek, Devonian chert production; **Fairview Field**, Ordovician (Knox) dolomite—one well, 1.8 MMcf monthly.
- b. Cumulative production** Cumulative production for Star Field (Lamar County, Alabama) producing from a combination trap and numerous horizons:

Producing Formation (gas sands) (10/98)	Cumulative Oil (10/98)	Cumulative Gas (10/98)	Producing Wells
Carter (Miss).....	99,799.....	19,218,189.....	7
Chandler (Penn).....	27,543.....	226,233.....	0
Fayette (Penn).....	0.....	10,400.....	1
Lewis (Miss).....	14,248.....	13,146,529.....	7
Lower Nason (Penn).....	372.....	757,692.....	1
Lower Millerella (Miss).....	797.....	1,264,601.....	0
Upper Nason (Penn).....	128.....	187,983.....	0
Carter Oil (Miss).....	78,955.....	6838.....	1
Chandler Oil (Penn).....	865.....	0.....	0
Total Cumulative Production .	222,707.....	34,818,492.....	17

**Economic
Characteristics:**

- a. Inert gas content**
- b. Recovery** Low, in south Pickens County, Alabama.
- c. Pipeline infrastructure** Very good. There are numerous gas lines in the basin.
- d. Exploration maturity relative to other basins** mature

- e. Sediment consolidation** Consolidation/porosity reduction occurs with depth of burial.
- f. Porosity/completion problems** Most wells are shallow and problem-free. Low porosity occurs in south Pickens County, Alabama (S.D. Champlin and R.L. Ericksen, Office of Geology, State of Mississippi, 1999, personal communication).
- g. Permeability** 0.01 to 100 md
- h. Porosity** 5-17%

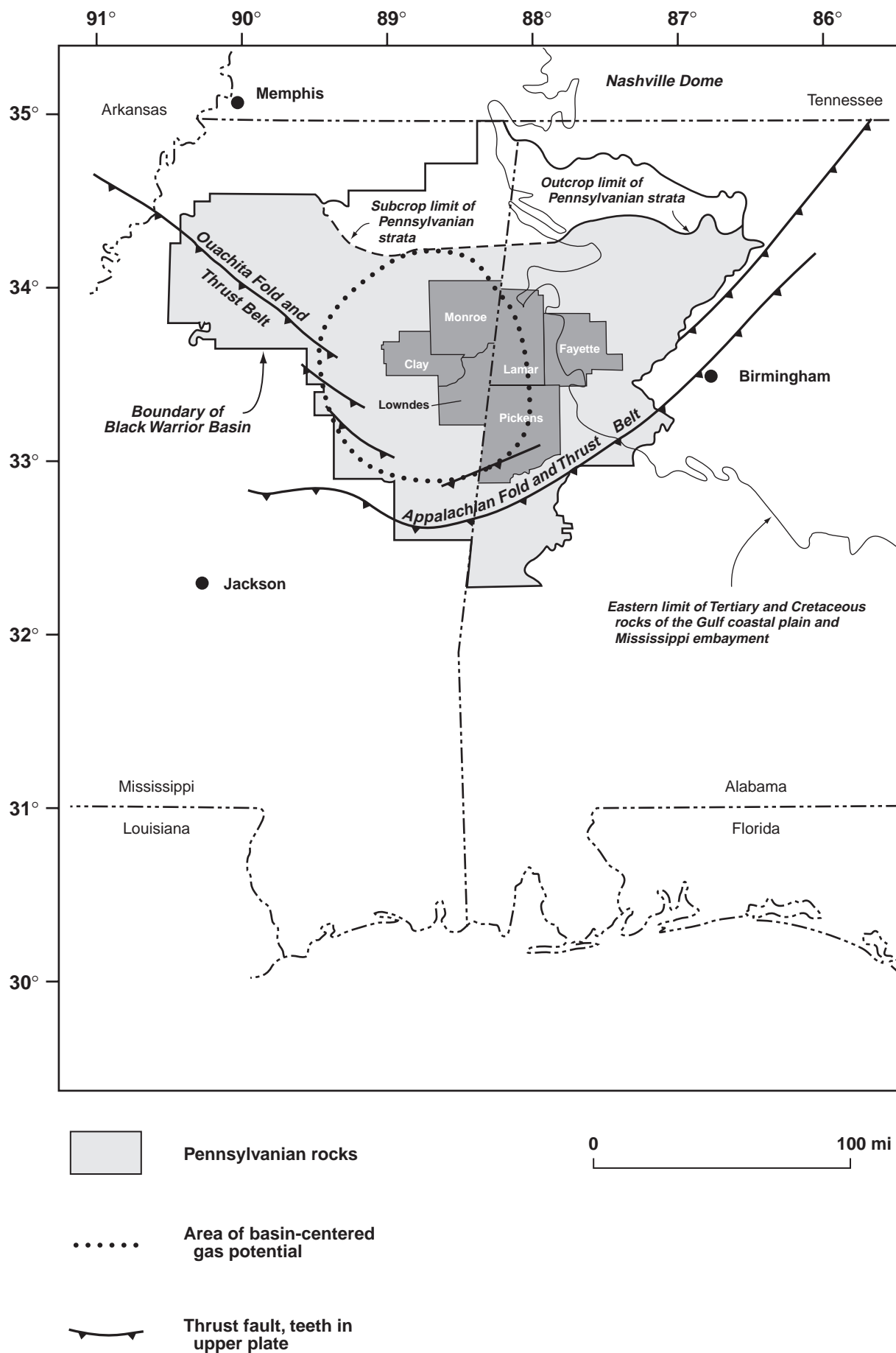


Figure 11. Location map of Black Warrior Basin, Mississippi and Alabama. After [Ryder \(1994\)](#).

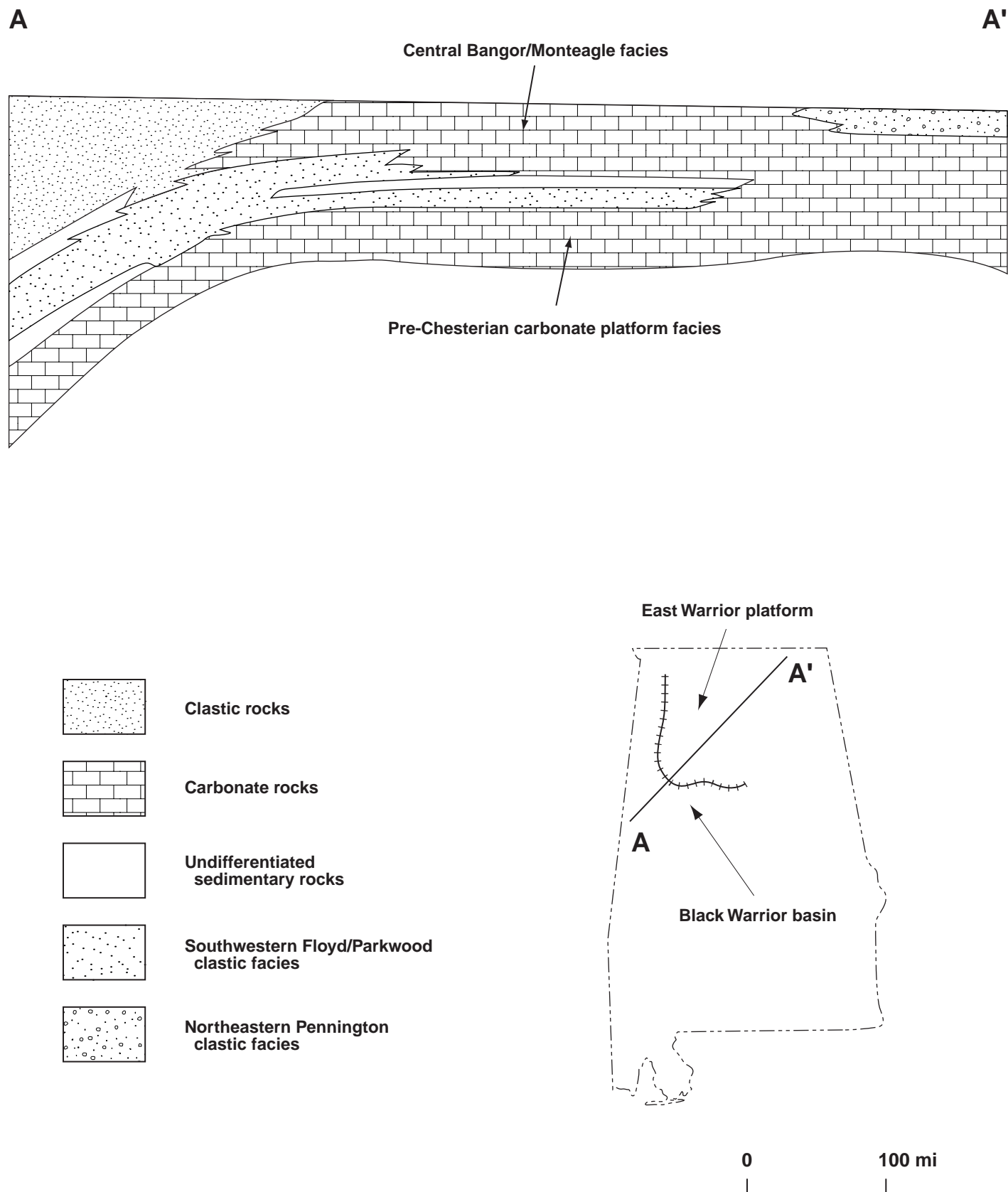


Figure 12. Regional cross section of northwestern Alabama showing lithofacies of Mississippian strata across East Warrior platform into Black Warrior basin. After [Bearden and Mancini \(1985\)](#).

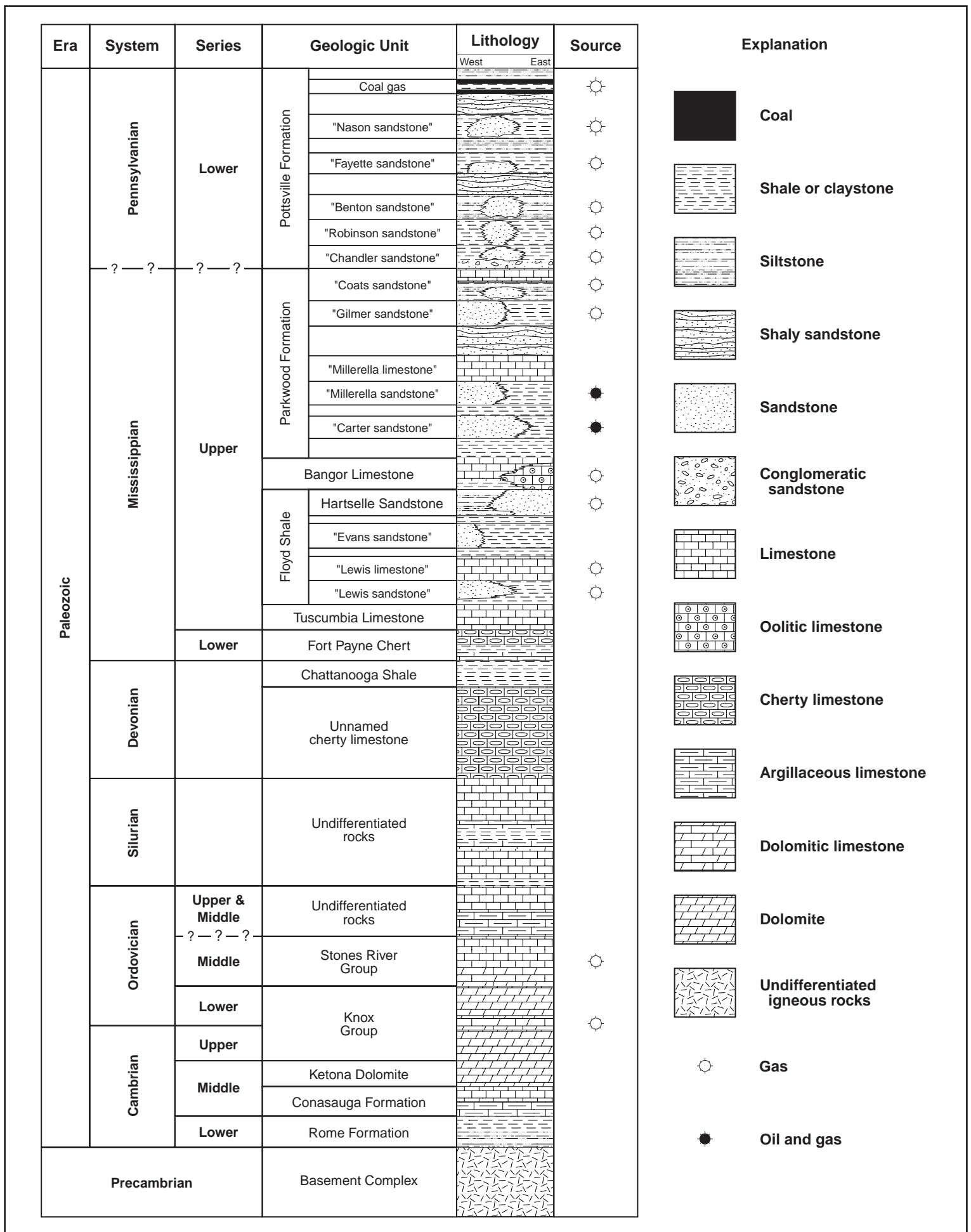


Figure 13. Generalized stratigraphic column for the Black Warrior basin, Alabama. After [Montgomery \(1986\)](#).

CENTRAL ALASKA BASINS

GEOLOGIC SETTING

The interior basins of Alaska cover a broad area extending from the Canadian border on the east to the Bering Sea on the west. There are a number of basins (Kandik, Yukon-Koyukuk, Kuskokwim, Bethel, Nenana, Tanana) that have been included in the Central Alaska Province of recent USGS assessments ([Figure 14](#)). The Central Alaska Province covers about 300,000 square miles between the Brooks Range on the north and the Alaska Range on the south ([Stanley, 1996](#)).

Central Alaskan geology is complex and varied, characterized by fold and thrust belts. Diverse crustal terranes formed along the ancestral North American cratonic margin, and structural deformation in this region is often severe ([Magoon, 1993](#)). Much of central Alaska experienced deformation in late Cretaceous to early Tertiary time ([Stanley, 1996](#)). The basins include areas of complexly deformed and locally metamorphosed flysch deposits underlying thick Cenozoic nonmarine sediments ([Kirschner, 1988](#)).

Three types of basins occur within the central Alaska ([Magoon and Kirschner, 1990](#)):

1. Segments of the Cordilleran fold and thrust belt. The Kandik basin represents such a segment, and is characterized by thrust-faulted anticlines that largely affected clastic and carbonate reservoirs of Paleozoic to Tertiary age. The right-lateral Tintina fault truncates the basin on the southwest ([Magoon, 1993](#)).
2. Mesozoic flysch basins. The flysch belts and flysch terranes represent volcanic-plutonic arc-basin deposits ([Magoon and Kirschner, 1990](#)). The flysch belts of the Yukon-Koyukuk, Kuskokwim, and Bethel basins consist of deep marine turbidite sandstones and shales, shallow marine alluvial fans, and coal bearing deltaic and fluvial facies ([Stanley, 1996](#)).
3. Cenozoic basins. These consist of undeformed to moderately deformed strata reflecting a distinctive gravity low ([Magoon and Kirschner, 1990](#)). They include a thick sequence of Tertiary and Quaternary rocks overlying Precambrian to Mesozoic igneous and metamorphic rocks ([Stanley, 1996](#)).

The stratigraphic section consists of a sequence of Precambrian rocks overlain by a succession of Paleozoic to Cenozoic sediments. [Figure 15](#) illustrates the generalized stratigraphic nomenclature common across the Central Alaska province. The Kandik basin contains the thickest stratigraphic section, with Proterozoic to Cenozoic rocks having a cumulative thickness greater than 40,000 feet ([Hite, 1997](#)). The Paleozoic section is approximately 15,000 feet thick. An unconformity at the top of the McCann Hill chert separates the Lower Paleozoic continental margin sediments from the overlying Upper Devonian to Permian foreland basin sequence ([Hite, 1997](#)). The Nenana and Middle Tanana basins contain an assemblage of sedimentary rocks from the Middle and Lower Miocene to Pliocene Usibelli group, which nonconformably overlie Precambrian and Paleozoic rocks ([Stanley et al., 1990](#)). The Bethel and Yukon-Koyukuk basins contain thick, widely distributed Cretaceous strata, including a large volume of volcanic rocks. Basal andesitic rocks are overlain by about 10,000 feet of graywacke and mudstones of lower Cretaceous Albian age ([Patton, 1971](#)).

HYDROCARBON POTENTIAL

There is no known hydrocarbon production in the basins of central Alaska. Drilling is very sparse, but the few wells drilled have encountered numerous shows of oil and gas. Other similar regions in Alaska are richly productive. Exploration efforts began in the Central Alaska basins as a result of hydrocarbon discoveries on the North Slope. Cretaceous strata similar to those on the North Slope exist beneath alluvial lowlands. Operators drilled a 12,000 foot well near Nulato on the Yukon River, and a 15,000 foot hole in the Yukon-Koyukuk basin. Neither wells had commercial shows ([Patton, 1971](#)).

The sedimentary sequences in central Alaskan basins may provide favorable settings for basin-centered hydrocarbon accumulations. Reservoir rocks in the Tertiary basins of central Alaska may be similar to the reservoirs in the producing fields of the Cook Inlet-Beluga-Sterling play ([Magoon and Kirschner, 1990](#)).

The Kandik and Middle Tanana basins appear to have the greatest hydrocarbon potential ([Grether and Morgan, 1988](#)). The Kandik and Yukon Flats basins may contain significant reserves of oil and gas within a 40,000 feet thick sedimentary package.

Three exploratory wells have been drilled in the Kandik basin. These wells encountered some porosity and bitumen in Devonian carbonates ([DiBona and Kirschner, 1984](#)). The Triassic Glenn Shale in the Kandik basin is an organic equivalent to the Shublik Formation of the North Slope and may have generated as much as 1.5 billion barrels of oil per cubic mile of sediment ([Hite, 1997](#)). In the Middle Tanana basin, only two exploratory wells have been drilled—the Unocal Nanana No. 1, and the ARCO Totek Hills No. 1. Both wells penetrated a thick Tertiary coal-bearing section of the Usibelli Group and terminated in metamorphic basement ([Smith, 1995](#)). The ARCO Totek Hills well was drilled on the basin flank and passed through 3,015 feet of Tertiary rocks. The sandstones averaged 17% porosity and 11 md permeability. The claystones contained Type II kerogen and indicate some oil potential ([Grether and Morgan, 1988](#)). [Smith \(1995\)](#) suggests that Tertiary coals of the Yukon Flats, Nenana, and Middle Tanana basins provide opportunities for commercial gas production.

Three hypothetical petroleum systems occur in central Alaska ([Stanley, 1996](#)):

1. Cenozoic gas. This system includes organically rich source rocks and has a potential for nonassociated gas in undeformed to moderately deformed strata.
2. Mesozoic gas. This system lies within sequences of flysch deposits, particularly in the Yukon-Koyukuk and Kuskokwim basins where various authors have reported lateral facies changes from deep marine turbidites to deltaic and shallow marine sediments ([Patton, 1971](#); [Nilsen, 1989](#); and [Box and Elder, 1992](#)). These facies changes indicate possible stratigraphic traps and may contain a basin-centered gas accumulation. The Benedum Nulato Unit No. 1 well drilled in the Koyukuk basin penetrated gas-prone kerogens in the Cretaceous section ([Stanley, 1996](#)).
3. Paleozoic oil. This system includes Ordovician, Silurian and Devonian graptolitic shales similar to ones found in basins elsewhere in North America, the Middle East and North Africa that contain oil-prone kerogen ([Klemme and Ulmishek, 1991](#)). These rocks may be potential sources for oil, and if heated sufficiently, a source for natural gas as well.

EVIDENCE FOR BASIN-CENTERED GAS

In the central Alaska basins, basin-centered hydrocarbon accumulations potentially exist within thick fluvial and lacustrine units: sandstones, conglomeratic sandstones, turbidites, shales, siltstones and coals. Available source and maturation data (TOC, TAI, Ro, and Tmax) indicate that the basins are marginally mature to overmature ([Stanley et al., 1990](#); [Smith, 1995](#)). However, [Stanley \(1996\)](#) believes that the late Cretaceous and Tertiary source rocks are thermally immature.

The Kandik and Middle Tanana basins appear to have the most potential for basin-centered gas accumulation. In the Middle Tanana basin, [Stanley et al. 1990](#) estimate the top of the oil window ($R_o = 0.6$) occurs at depths exceeding 4,500 ft. Vitrinite reflectance values in the Kandik basin fall within the gas generation window ([Figure 16](#)). In the Middle Tanana basin, data from the ARCO Totek Hills No. 1 well indicates the presence of Types II and III kerogen, indicating the Usibelli Group strata may be oil and gas-prone. Based on present information regarding thermal maturity, wells drilled in the deeper parts of the central Alaska basins may encounter strata buried below the top of the oil window, and therefore, potentially encounter basin-centered hydrocarbon accumulations.

KEY ACCUMULATION PARAMETERS

Identification

Central Alaska, Interior basins, Paleozoic, Upper Triassic, and Tertiary potential basin-centered gas accumulations

Geologic Characterization of Accumulation:

- | | |
|---|---|
| a. Source/reservoir | Ford Lake shale, Calico Bluff, Glenn Shale (Devonian to Jurassic), Usibelli Group (Tertiary); Kerogen types: II, III, and IV. Reservoir: Nation River, Calico Bluff, shallow marine limestones of the Permian Tahkandit |
| b. Total Organic Carbons (TOCs) | Formation, unnamed sandstones of Cretaceous and Tertiary ages.
Kandik basin: 7% (Glenn Shale); Holitna basin: 0.61 to 1.59% (Cretaceous Kuskokwim group); Middle Tanana basin: 3.6% (Sanctuary formation of Tertiary Usibelli group), outcrop: 0.5 to 3.5%. |
| c. Thermal maturity | Kandik basin: $T_{max} = 427-579^{\circ}C$, $R_o = 0.8\%$ (mean); Middle Tanana basin: $T_{max} = 414$ to $434^{\circ}C$, $R_o = 0.6\%$ (below 4500 ft depth). |
| d. Oil or gas prone | Primarily oil prone; however, level of maturity probably reaches the "gas window." |
| e. Overall basin maturity | Marginally mature to overmature (similar to North Slope), probably in the deep parts of the basins and in shallower areas near high heatflow pathways; marginally immature on basin flanks where burial depths have been limited. |
| f. Age and lithologies | Early Cambrian to late Permian (sandstones, shales and carbonates), Upper Cretaceous to Tertiary (sandstones, conglomeratic sandstones, shales, coals and siltstones). |
| g. Rock extent/quality | Basin-wide source and reservoir rock distribution; highly variable rock quality is anticipated as exists on the North Slope, including problems with silica cementation, siderite cementation, calcite cementation, and swelling and moveable clays. |
| h. Potential reservoirs | No production exists; however, potential reservoirs include Proterozoic Tindir group; Paleozoic carbonates (including Devonian Nation River, Mississippian and Pennsylvanian Calico Bluff formation); shallow marine limestones of the Permian Tahkandit formation; Cretaceous Kandik group; Tertiary Usibelli group; and other unnamed sandstones of Cretaceous and Tertiary ages. |
| i. Major traps/seals | Structural and stratigraphic, Devonian and Pennsylvanian argillites, shales, siltstones and mudstones of Cretaceous and Tertiary ages. |
| j. Petroleum generation/migration models | Weimer's (1996) "Cooking Pot" model with current hydrocarbon generation and relatively short distance migration and Meissner's (1978) Bakken shale expulsion model. |
| k. Depth ranges | Surface to 40,000 ft, in some Tertiary basins, top of the oil generation window may range from 5,000 to 10,000 ft, depending upon thermal gradients and vitrinite reflectance values. |
| l. Pressure gradients | |

**Production and Drilling
Characteristics:**

- a. Important fields/reservoirs**
- b. Cumulative production**

**Economic
Characteristics:**

- a. Inert gas content**
- b. Recovery**
- c. Pipeline infrastructure** Non-existent, except for the trans-Alaska oil pipeline.
- d. Exploration maturity relative to other basins** Immature
- e. Sediment consolidation** Moderate or better consolidation.
- f. Porosity/completion problems** Unknown due to no known completions.
- g. Permeability**
- h. Porosity**

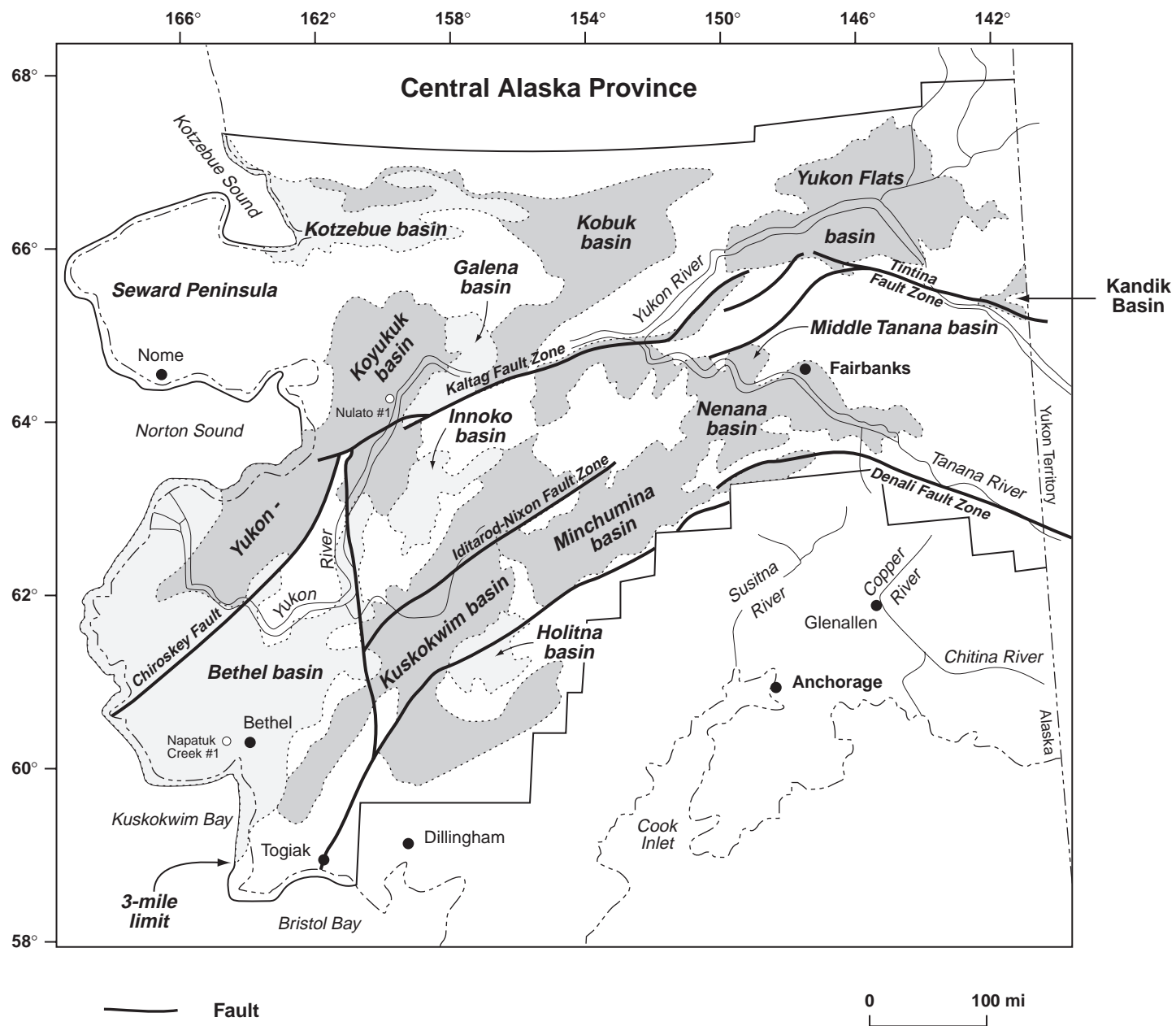


Figure 14. Map showing various provinces and basins in central Alaska (boundaries approximate). After [Magoon \(1993\)](#) and [Stanley \(1996\)](#).

System	Kandik Basin	Interior Lowlands Basins
Tertiary	Sandstone, mudstone, and conglomerate	Nenana Gravel Usibelli Group
Cretaceous		Non-deposition or removal by erosion
Jurassic	Glenn Shale	
Triassic		
Permian	Tahkandit Limestone	
Pennsylvanian		
Mississippian	Calico Bluff Formation	
	Ford Lake Shale	
Devonian		
	Nation River Formation	
	McCann Hill Chert	
Silurian	Road River Formation	
Ordovician		
Cambrian	Hillard Limestone	
	Adams Argillite	
	Funnel Creek Limestone	
Precambrian	Tindir Group	Birch Creek Schist

Figure 15. Generalized stratigraphic column for Kandik and Interior Lowlands basins, central Alaska. After [Stanley et al. \(1990\)](#), and [Magoon \(1993\)](#).

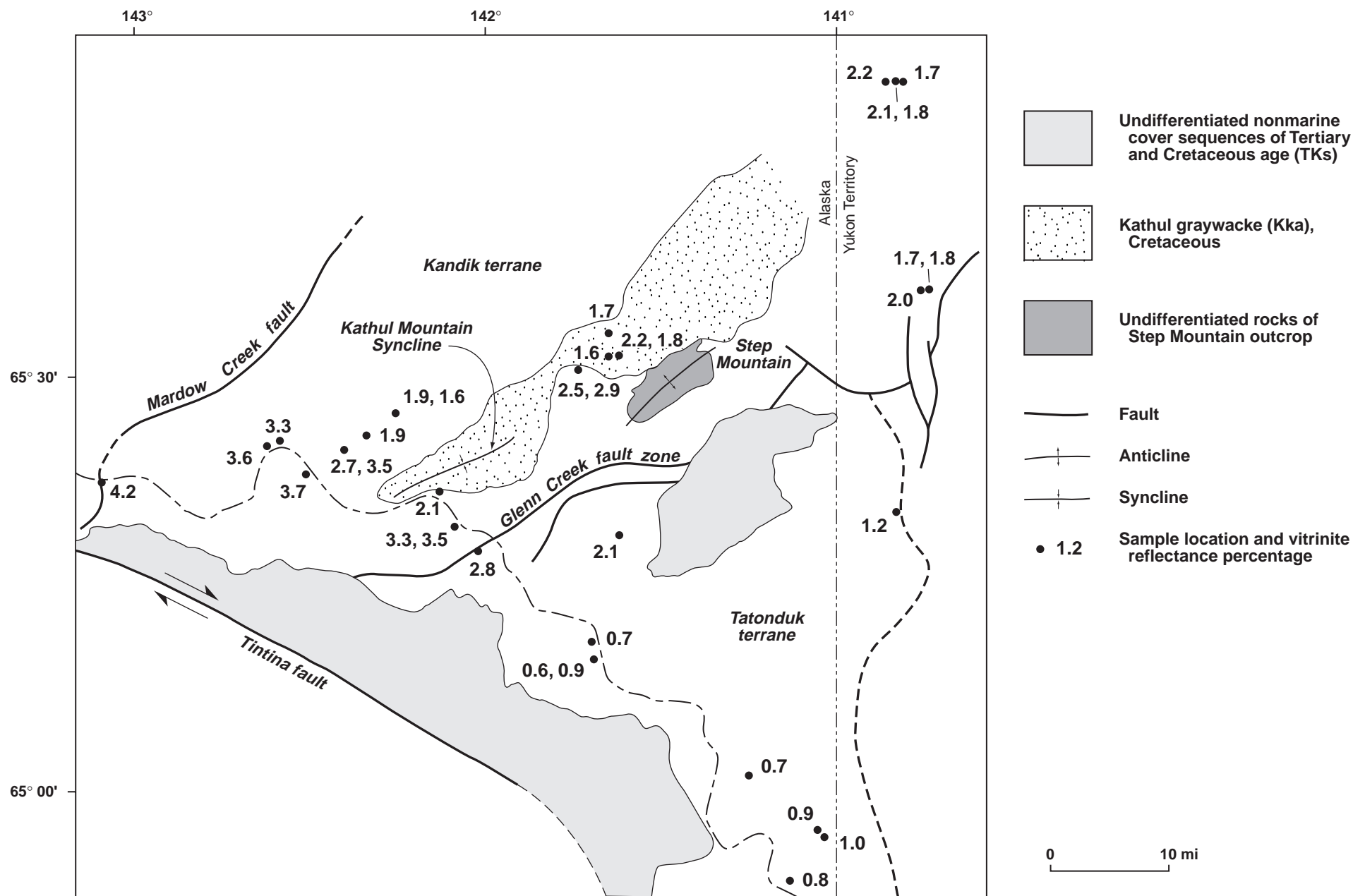


Figure 16. Map of the Kandik basin showing sample locations for and values of vitrinite reflectance (%R_o) relative to major geologic structures (Kathul Mountain syncline and Step Mountain anticline). After [Laughland et al. \(1990\)](#).

CHUAR GROUP (PRECAMBRIAN PARADOX BASIN)

GEOLOGIC SETTING

The Late Proterozoic Chuar Group extends from northern Arizona into southwestern Wyoming. [Figure 17](#) depicts a map of the regional extent and outcrop locations of the Chuar rocks. Exposures in the Grand Canyon reach a thickness of approximately 5,370 ft, and the rocks consist of organic-rich gray-black shale and siltstone interbedded with sandstones and cryptalgal and stromatolitic carbonates ([Reynolds et al., 1988](#); [Palacas, 1992](#)). The Chuar Group contains the Galeros Formation and the overlying Kwagunt Formation ([Figure 18](#)). The lithologies indicate various cyclical depositional environments, including a sediment-starved basin rich in organic material, coastal and alluvial plains, paludal swamp, and nearshore marine. Deposition of the Chuar Group occurred on a marine embayment on the passive edge of a continent ([Reynolds et al., 1988](#)).

HYDROCARBON PRODUCTION

There have been some exploratory wells that penetrated the Chuar, but no production. Shows and tests of this section are rare. Geochemical analyses of outcrop samples from the Walcott Member of the Kwagunt Formation indicate good to excellent source-rock potential and thermal maturity for oil generation. Tmax values range from 424 to 452 °C. Total organic carbon values (TOCs) average ~ 3.0 %, with highs ranging from 8.0 to 10.0 %. Samples from the upper part of the Walcott yielded higher values than those from the lower part ([Palacas, 1992](#)). The underlying Galeros Formation shows lower TOC values and appears thermally overmature, but still might be within the window for gas generation.

EVIDENCE FOR BASIN-CENTERED GAS

The Walcott Member demonstrates good source-rock potential and may contain sandstones with good reservoir quality. Stratigraphic and conventional structural prospects may exist if the source rock is continuous.

KEY ACCUMULATION PARAMETERS

Identification

Grand Canyon area, Late Proterozoic, Chuar Group, Kwagunt and Galeros Formations

Geologic Characterization of Accumulation:

- a. **Source/reservoir** The Walcott Member may be a source rock; interbedded sandstones may be reservoirs.
- b. **Total Organic Carbons (TOCs)** Range from 1.0 % to 10.0% (average ~ 3.0%) in outcrop samples of the Kwagunt Formation. The values for the Galeros Formation are not available.
- c. **Thermal maturity** Tmax values in the Walcott Member of the Kwagunt Formation range from 424 to 452° C.
- d. **Oil or gas prone** The Walcott Member is oil prone. The lower portions of the Kwagunt Formation and the Galeros Formation are gas-prone.
- e. **Overall basin maturity**
- f. **Age and lithologies**
- g. **Rock extent/quality**
- h. **Potential reservoirs**
- i. **Major traps/seals**
- j. **Petroleum generation/migration models**
- k. **Depth ranges**
- l. **Pressure gradients**

**Production and Drilling
Characteristics:**

- a. Important
fields/reservoirs**
- b. Cumulative production**

**Economic
Characteristics:**

- a. Inert gas content**
- b. Recovery**
- c. Pipeline infrastructure**
- d. Exploration maturity
relative to other basins** Because of the virtually untested nature of the deposit, it is immature.
- e. Sediment consolidation**
- f. Porosity/completion
problems**
- g. Permeability**
- h. Porosity**

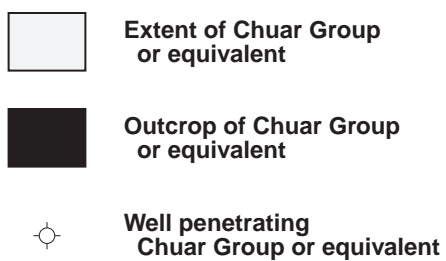
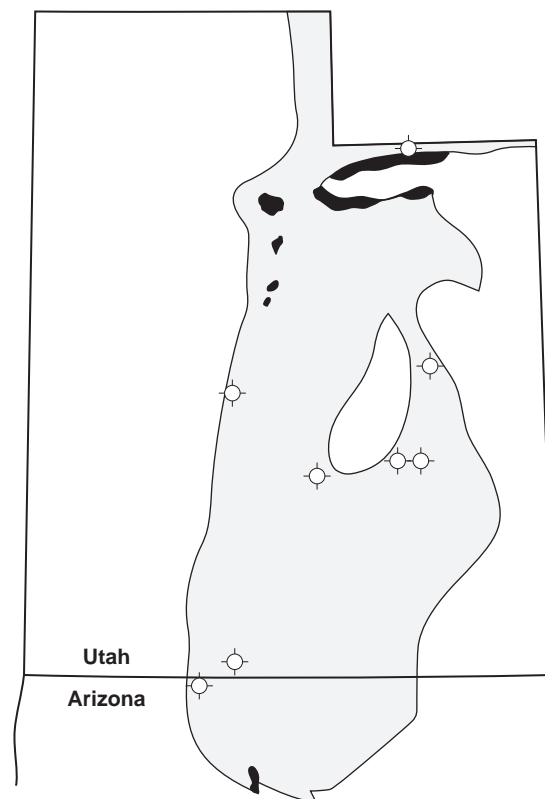
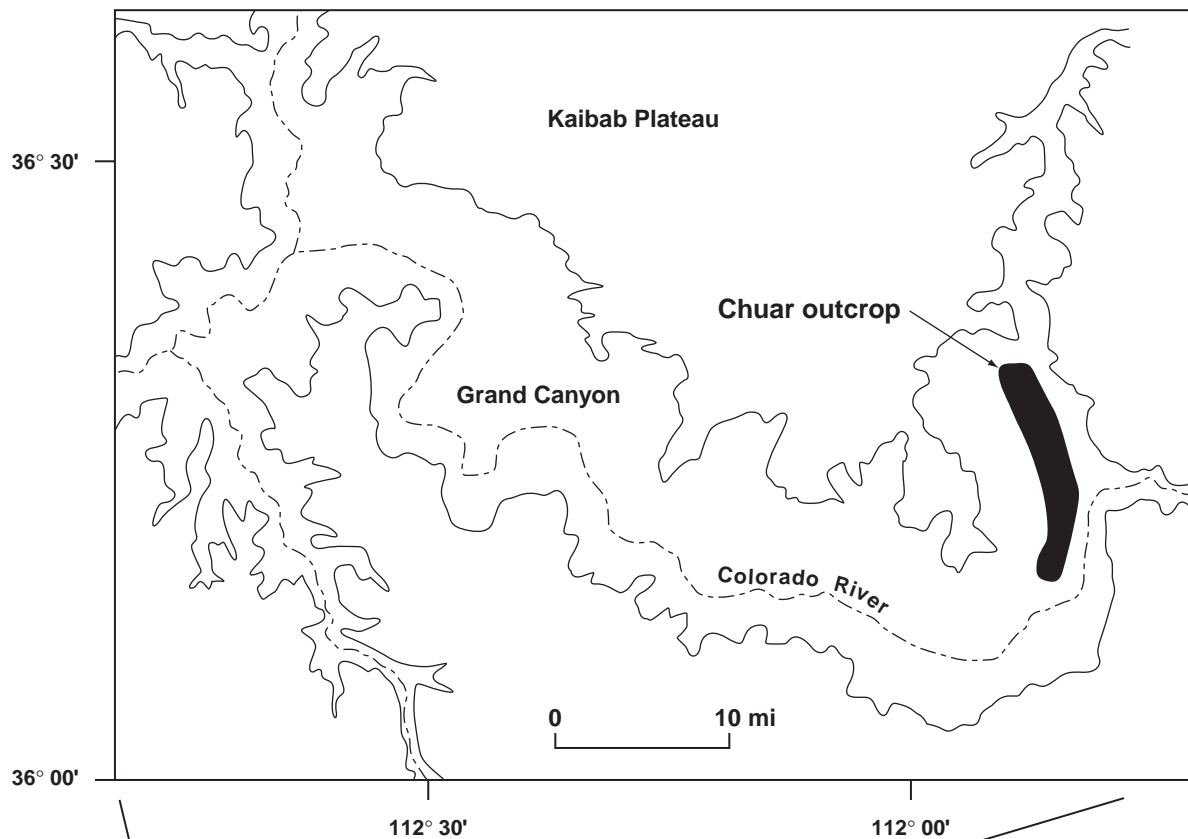
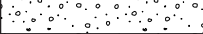
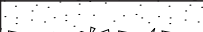
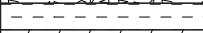
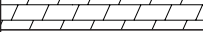
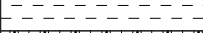
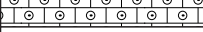

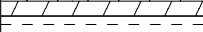

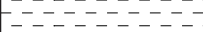
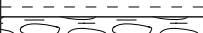
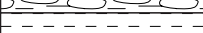
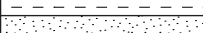

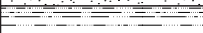






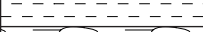
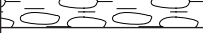


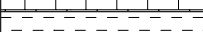
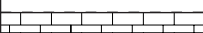
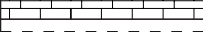
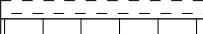


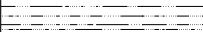
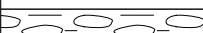
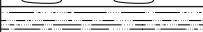



Figure 17. Map showing regional extent and outcrops of Chuar Group rocks in Utah and Arizona. After [Palacas \(1992\)](#).

System	Group	Formation	Member	Lithology
Cambrian		Tapeats Ss		
		Sixtymile		
Precambrian	Chuar	Kwagunt	Walcott	  
				
			Awatubi	  
		Galeros	Carbon Butte	 
			Duppa	  
			Carbon Canyon	  
				  
				  
			Jupiter	  
			Tanner	   
		Nankoweap		
		Cardenas Lava		  
	Unkar	Dox		



Shale



Red sandstone



Pisolitic chert



Basalt



Siltstone



Coarse sandstone



Limestone



Chert and breccia



Biohermal
stromatolite



Dolomite

Figure 18. Stratigraphic column for Chuar Group. After [Ford \(1990\)](#).

COLUMBIA BASIN

GEOLOGIC SETTING

The Columbia Basin is located in south-central to southwestern Washington, northeastern Oregon, and western Idaho (Figure 19). Johnson et al. (1993) defined the basin as a broad low-lying area between the Cascade Range to the west, the Rocky Mountains to the east, the Okanogan highlands to the north, the Blue Mountains to the south, the western end of the Yakima fold belt, and the eastern limit of the Palouse slope.

Within the Columbia Basin, Johnson et al. (1997) postulated a basin-centered gas deposit bounded by the Chumstick basin and Swauk basin to the northwest, the easterly apron of the Cascade Range and a projection of the Straight Creek fault zone to the west and southwest, the Columbia River and part of the Blue Mountains to the south, and the projection of the Entiat fault to the east and northeast (Figure 20).

The sedimentary rocks in the basin are covered by up to 20,000 ft of Miocene basalt that originated from dike systems near the Washington-Oregon-Idaho border area approximately 6.5 to 16.5 ma (Figure 21) (Johnson et al., 1997). Mesozoic sediments underlie the basalts. Rocks associated with subduction complexes, volcanic island arcs, and ophiolites and other sedimentary packages indicate a complex history of accretion of allochthonous terranes and arc tectonism. Sediments crop out along the northern, eastern, and southern margins of the basalt plateau and probably underlie the entire plateau.

Development of the Idaho Batholith in Cretaceous time and unconformable deposition of marine sediments marked the end of accretionary deposition. This was followed by deposition of early Tertiary nonmarine sedimentary and volcanic rocks. Tectonic activity included volcanism and transtension in northeastern Washington, strike-slip faulting and folding in central and western Washington, and prolific volcanism in central Oregon. Paleocene to Eocene arkoses, mudstones and coals were deposited, varying in thickness from a few hundred feet to more than 20,000 ft. Sparse exploratory drilling and magnetotelluric data suggest that an average 5,000 to 10,000 ft of sedimentary rocks exist below the basalts in central Washington (Tennyson, 1996).

The western margin of the Columbia plateau contains Oligocene to Quaternary volcanic rocks of the Cascade arc complex. Deformation of the basalts occurred with folding and reverse faulting in the western part of the plateau (Tennyson, 1996).

HYDROCARBON PRODUCTION

The Rattlesnake Hills field is the only commercial gas field producing in the Columbia Basin. The field was discovered in 1913 and developed in 1930, and produced approximately 1.3 BCFG through 1941 from depths ranging between 700 ft and 1300 ft. The gas was mostly methane and 10% carbon dioxide. A faulted anticlinal structure trapped the gas in a vesicular basaltic zone thought to be clay sealed. Johnson et al. (1993) believe the gas migrated from Eocene coals buried below the basalts.

EVIDENCE FOR BASIN-CENTERED GAS

Tests in deep wells in the Yakima-Pasco area yielded gas at depths ranging from 8,300 to 12,700 ft. Lingley (1995) estimated pressure gradients of 0.42 psi/ft to 0.45 psi/ft at 5,000 to 10,000 feet and 0.62 psi/ft at 14,000 ft depth, indicating moderate overpressures in the deep part of the basin. Johnson et al. (1997) note most drill-stem tests recovered water-free gas, but some did recover water.

Source rocks for this accumulation may be Eocene coals and carbonaceous shales interbedded with arkosic fluvial sandstones. Eocene sediments may reach a depth of 17,000 ft in the center of the basin.

KEY ACCUMULATION PARAMETERS

Identification

Eastern Oregon-Washington Province, Columbia Plateau/Basin, basin-centered gas play

Geologic Characterization of Accumulation:

- | | |
|---|---|
| a. Source/reservoir | Eocene Swauk, Chumstick, Roslyn, and Manatash formations |
| b. Total Organic Carbons (TOCs) | Values range from 0 to 17%. |
| c. Thermal maturity | R _o 0.5 – 1.43 |
| d. Oil or gas prone | Gas prone; mostly type III kerogens with limited type II kerogen |
| e. Overall basin maturity | Maturation levels are moderate, maturation levels increase west of the basin toward the crest of the Cascade mountains. Possibly overmature in the deepest parts of the basin. |
| f. Age and lithologies | Eocene, arkosic sands, coals, and shales. |
| g. Rock extent/quality | Wide source and reservoir rock distribution, rock quality is unknown except around basin margins and in the few wells that have been drilled. Expected reservoir quality is variable depending upon clay content, zeolite alteration and interbedded shales and coals. |
| h. Potential reservoirs | None presently; Rattlesnake Hills gas field produced 1.3 BCFG from 1930 to 1941 from the Miocene age Columbia River Basalt Group. Vertical migration of gas from Eocene source rocks buried below the basalt flows. |
| i. Major traps/seals | Interbedded Eocene age shales and coals. |
| j. Petroleum generation/migration models | both in-situ generation and long distance migration of gases shales and coals. Hydrocarbon generation is probably ongoing at depths below 12,000 feet. Geothermal gradients range from 28 to 58° C per km (Lingley, 1995).
Weimer's (1996) Denver basin cooking pot model might apply. |
| k. Depth ranges | Accumulation depths are thought to range from 8300 feet to 17,000 feet. |
| l. Pressure gradients | range from estimated 0.42 psi/ft at 5,000 ft depth to 0.45 psi/ft at 10,000 ft to 0.62 psi/ft at 14,000 ft. This conflicts with Johnson et al. (1997) which reported overpressuring occurring at depths of 8,300 ft to 12,700 ft. |

**Production and Drilling
Characteristics:**

- | | |
|---------------------------------------|---|
| a. Important fields/reservoirs | Rattlesnake Hills gas field |
| b. Cumulative production | Only production to date was from 1930-1941. Rattlesnake Hills field produced 1.3 BCFG from Miocene age basalts. |

**Economic
Characteristics:**

- | | |
|---|---|
| a. Inert gas content | Gases from the Rattlesnake Hills field were reported to contain 10% nitrogen by Wagner (1966) ; Hammer (1934) reported 2.45% nitrogen and 0.15% carbon dioxide. |
| b. Recovery | Recoveries may vary depending upon permeability, porosity and depth; diagenetic alteration may increase with depth. |
| c. Pipeline infrastructure | Poor |
| d. Exploration maturity relative to other basins | Immature |
| e. Sediment consolidation | Most rocks are well indurated. |
| f. Porosity/completion problems | Shales, clay and mica rich arcose sands have high alteration potential, may have swelling clays and will produce migrating fines problems, average porosities range from 6 to 15 percent. Shales and coals are interbedded with sands. Zeolite and chlorite alteration has been reported. |
| g. Permeability | Outcrop measurements range from 0.02 to 0.8 md. |
| h. Porosity | |

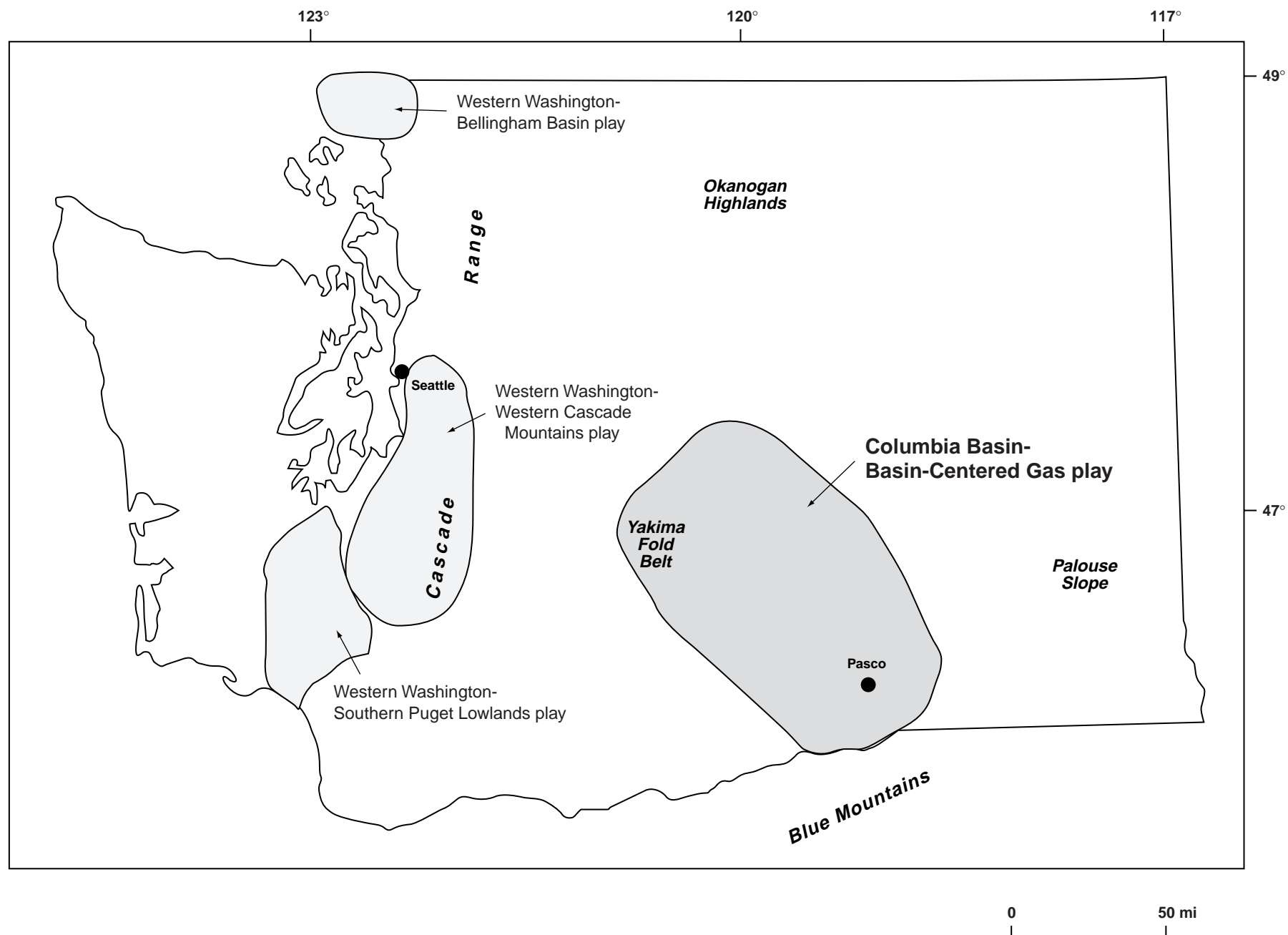


Figure 19. Map of Washington showing locations of unconventional petroleum plays. After [Johnson et al. \(1997\)](#).

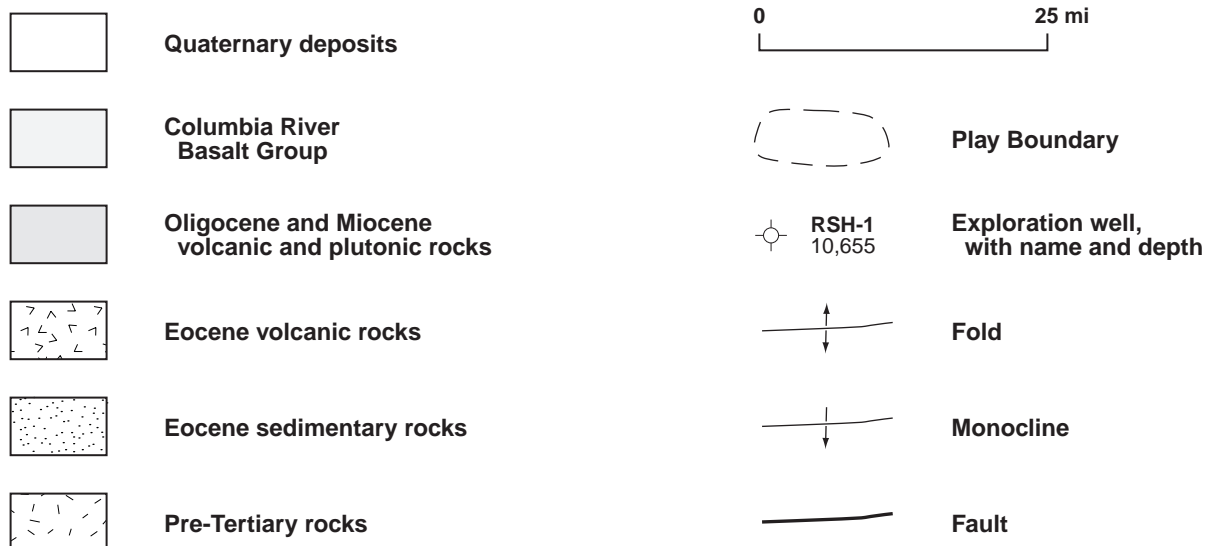
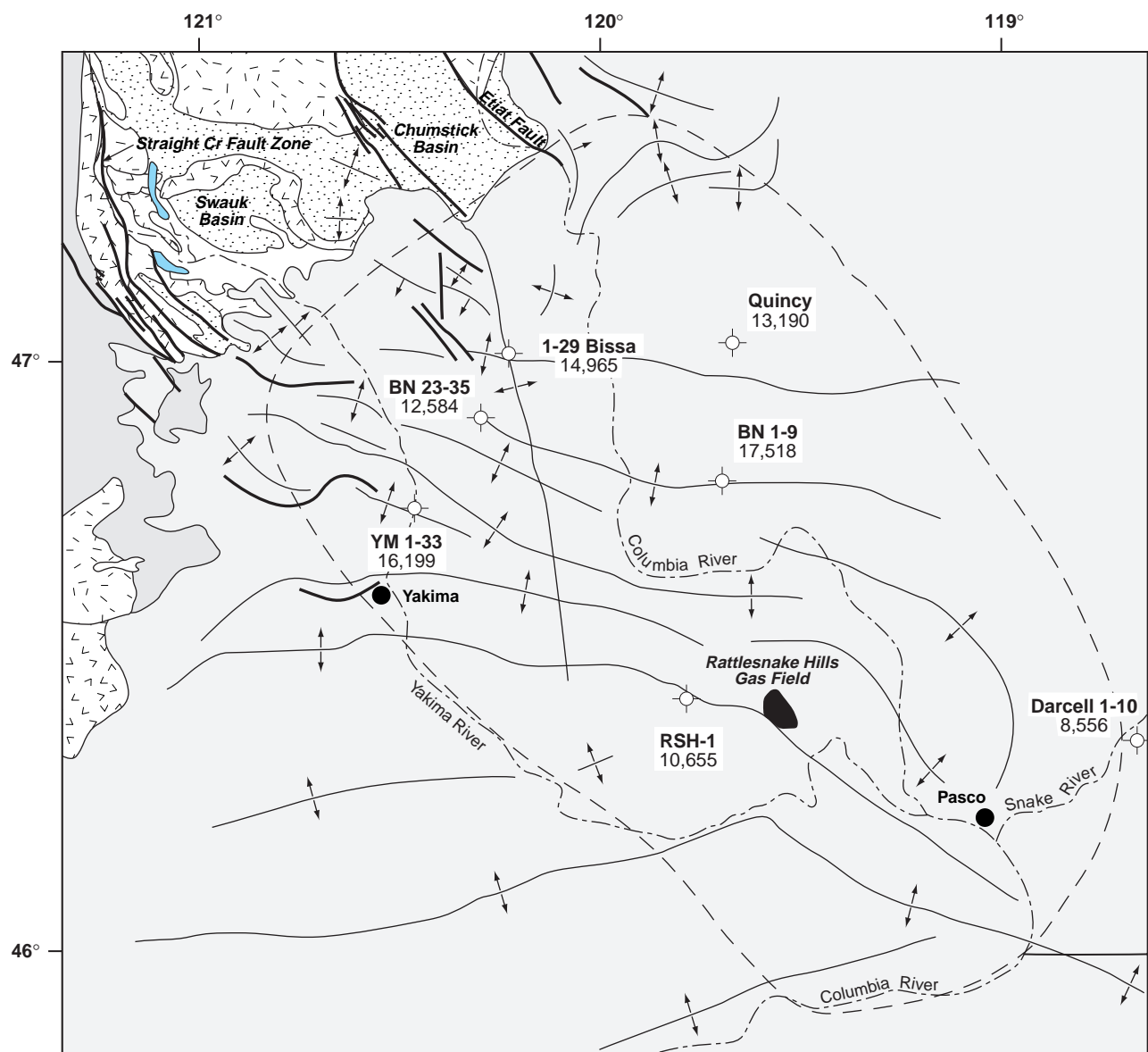


Figure 20. Geologic map of Columbia Basin, showing locations of basin-centered gas play and exploration wells. After Johnson et al. (1997).

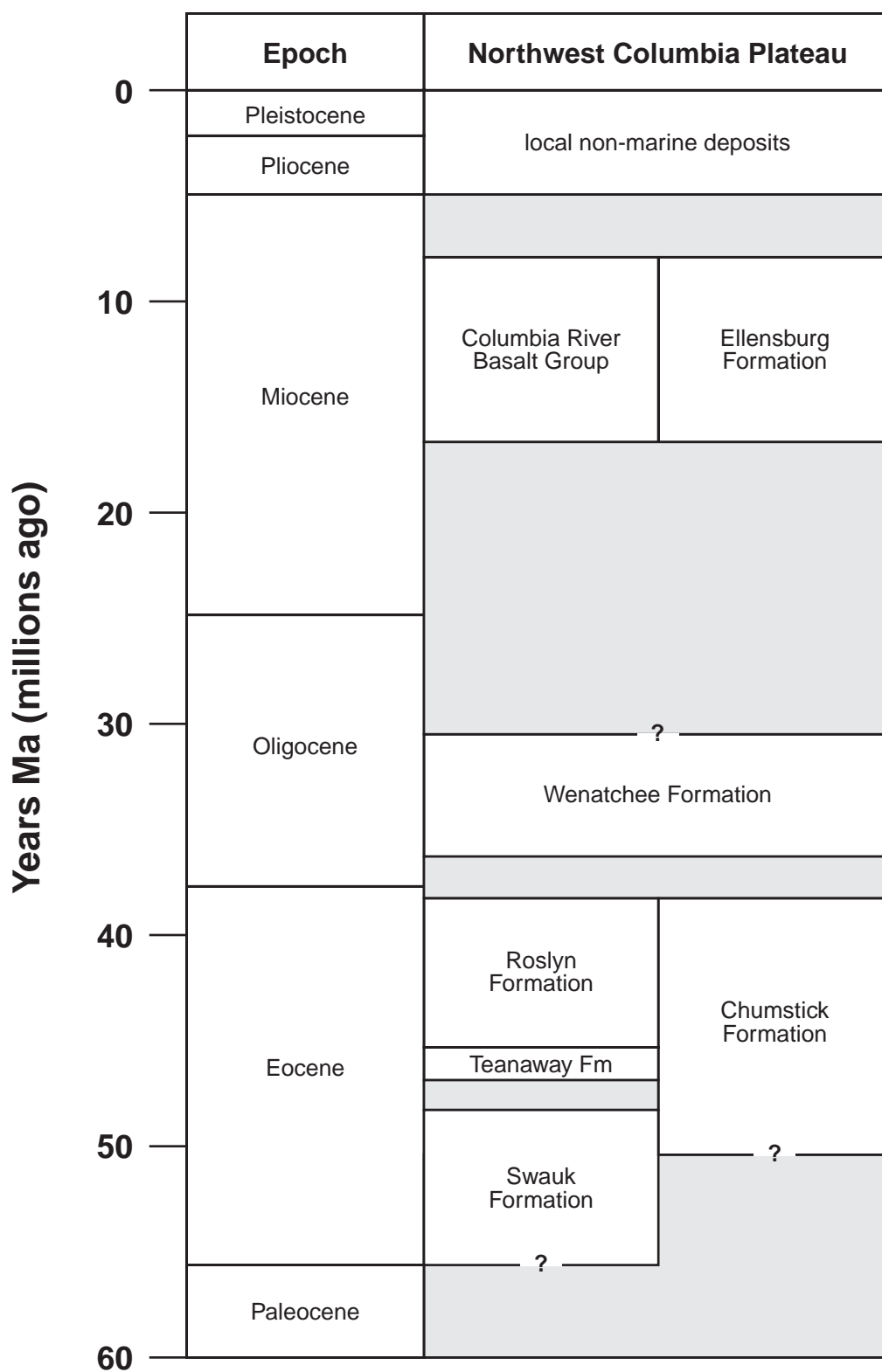


Figure 21. Stratigraphic column for Columbia Basin petroleum-play area. Shaded intervals indicate occurrences of erosion or no deposition. After [Johnson et al. \(1997\)](#).

COLVILLE BASIN, ALASKA

GEOLOGIC SETTING

The western Colville Basin covers about 64,000 square miles of the western half of Alaska's North Slope. The Herald Arch and the Chukchi Platform form the basin's western boundary and, west of Icy Cape and Point Barrow, "bend" the offshore part of the Colville trough axis northward into the Hanna Trough (Figure 22). The Barrow Arch borders the Colville's northern flank eastward from the Chukchi Sea, and parallels the present Arctic Ocean coastline almost to the Canadian border. The Brooks Range thrust belt defines the basin's eastern and southern limits, and partly overrides the Colville's south flank along the Southern Foothills (Figure 23).

The North Slope is primarily a composite basin whose northern edge includes late Paleozoic and Mesozoic continental-margin deposits overlain by Cretaceous and Tertiary foreland-basin sediments (Figure 24) (Bird, 1991). The Colville Basin itself appears generally asymmetrical, with the strata thickest along the Southern Foothills belt and generally thinning northward over the Barrow Arch (Figure 25).

Uplift of the Brooks Range fold and thrust belt began during the Late Jurassic and shed sediments northward into the foredeep Colville Basin. Termed the Brookian Sequence, these deposits are mostly clastic and unconformably overlie older Ellesmerian rocks along the Barrow Arch (Figure 26). The Ellesmerian Sequence includes sandstones, shales, and up to 25% carbonates. Both sequences contain substantial amounts of good to excellent quality source rocks in close physical and stratigraphic proximity to porous reservoir units (Figure 25). Colville Basin stratigraphy includes all of the Brookian Sequence and most of the Ellesmerian Sequence rocks. At the basin axis, the total combined thickness of the Ellesmerian and Brookian strata may exceed 32,000 ft (Bird, 1991).

HYDROCARBON PRODUCTION

Outside the Prudhoe Bay complex near the northeast end of the Colville Basin, there is little production on the North Slope. The Prudhoe Bay Field contains recoverable petroleum reserves exceeding 13 BBO; oil production generally comes from the Ivishak Sand member of the Upper Ellesmerian Sadlerochit Group, and from the Lisburne Group of carbonates in the Lower Ellesmerian.

The South Barrow gas field presently supplies domestic gas only to the town of Barrow.

EVIDENCE FOR BASIN-CENTERED GAS

To date, exploration outfits have drilled 41 wells deeper than 4,000 ft in and around the Colville Basin. Many wells had gas or oil shows, and consequently 13 prospects have been identified as potentially capable of yielding gas. Several wells produce gas at rates above 2 MMCFD.

Equivalent rocks in Colville strata have already sourced fields along the Barrow Arch, including Prudhoe Bay. Bird (1991) and Sedivy et al. (1987) reported total organic carbon (TOC) content for Colville source rocks generally ranged from 1.5 to 3.0 wt%, with some oil shales in the Endicott Group reaching 16%. Some of those same source rocks have created overpressure conditions in the Prudhoe Bay field and could have charged a basin-centered accumulation in the Colville Basin (Gognat, 1999, Global GeoData LLC, personal communication).

KEY ACCUMULATION PARAMETERS

Identification

Northern Alaska, Colville Basin, possible basin-centered accumulation

Geologic Characterization of Accumulation:

- | | |
|---|--|
| a. Source/reservoir | Sources: Upper Triassic and Neocomian rocks. Reservoirs: Ivishak Sand, Kuparuk River/Kemik Sands, Sag River Sand, sands within the Kingak Shale, plus sands within the Nanushuk Group, Colville Group, and Sagavanirktok Formation (Figures 25, 26, and 27). |
| b. Total Organic Carbons (TOCs) | Range from 1.5 to 3.0%; some highly organic "paper shales"/oil shale range up to 16% (Sedivy et al., 1987 ; Bird, 1991). |
| c. Thermal maturity | Maturity over much of the area falls within the peak-oil to peak-gas generation stage, with $R_o \pm 2.0$ (Figure 25 , Figure 27 , and Figure 28). The deepest parts of the basin may be cracking previously generated oil into gas. |
| d. Oil or gas prone | Both oil and gas prone. |
| e. Overall basin maturity | Mature; the base of the dry gas zone in the central Colville Basin area probably occurs below a depth of 19,500 ft (Johnsson et al., 1993). |
| f. Age and lithologies | Triassic and younger sands; Mississippian Endicott Group clastic and carbonate rocks. |
| g. Rock extent/quality | Potential 30,000 sq mi source and reservoir-rock distribution. Sandstones in the Triassic and younger strata often exceed 20% porosity (Gognat, 1999, Global Geodata LLC, personal communication). |
| h. Potential reservoirs | Ivishak Sand, Kuparuk River/Kemik Sands, Sag River Sand, sands within the Kingak Shale, plus sands within the Nanushuk Group, Colville Group, and Sagavanirktok Formation (Figures 25, 26, and 27). |
| i. Major traps/seals | All traditional hydrocarbon traps. |
| j. Petroleum generation/migration models | The Weimer (1996) "Cooking Pot" model, where generated hydrocarbons are expelled into the surrounding reservoir rocks. |
| k. Depth ranges | 4,000 through 21,000 ft. Some gas production from depths shallower than 4,000 ft, but occurring from smaller structural and stratigraphic traps unrepresentative of basin-centered accumulations (Figure 29). |
| l. Pressure gradients | Unknown, but many Prudhoe Bay wells intercept overpressured strata and some Brooks Range foothills wells may have shown overpressuring. |

**Production and Drilling
Characteristics:**

- | | |
|---------------------------------------|---|
| a. Important fields/reservoirs | South Barrow, Fish Creek, Umiat, Meade, Simpson, Wolf Creek, Gubik, Square Lake, East Umiat, East Barrow, East Kurupa, Eagle Creek, Walakpa, and Sikulik (Figure 30). |
| b. Cumulative production | See Figure 31 . Outside the Prudhoe Bay producing complex, there is little production on the North Slope. South Barrow Gas field presently supplies only domestic gas to the town of Barrow. |

**Economic
Characteristics:**

- | | |
|---|---|
| a. Inert gas content | Possible, but unknown. |
| b. Recovery | Unknown |
| c. Pipeline infrastructure | Poor to non-existent. |
| d. Exploration maturity relative to other basins | Immature |
| e. Sediment consolidation | Moderate to good. |
| f. Porosity/completion problems | Unknown |
| g. Permeability | Probably high, but variable. |
| h. Porosity | Highly variable, but porosity in reservoirs exceeds 20% (Gognat, 1999, Global Geodata LLC, personal communication). |

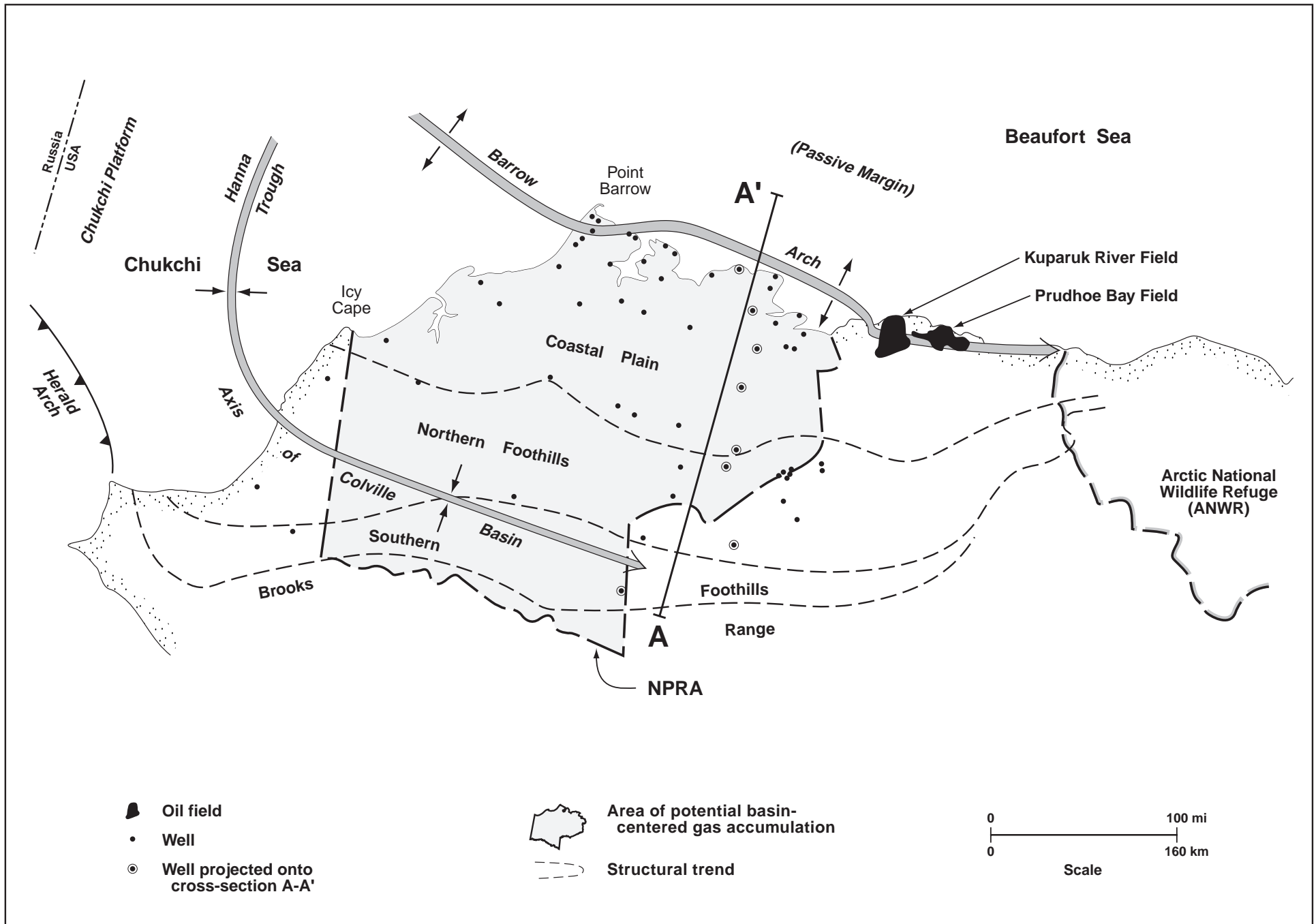


Figure 22. Map of Colville Basin, Alaska, showing generalized structural and stratigraphic trends, petroleum fields within the Colville River delta, wells, the area considered for potential basin-centered gas accumulation, and the location of cross section A-A' (Figure 25). After Kornbrath et al. (1997) and Molenaar et al., (1988).

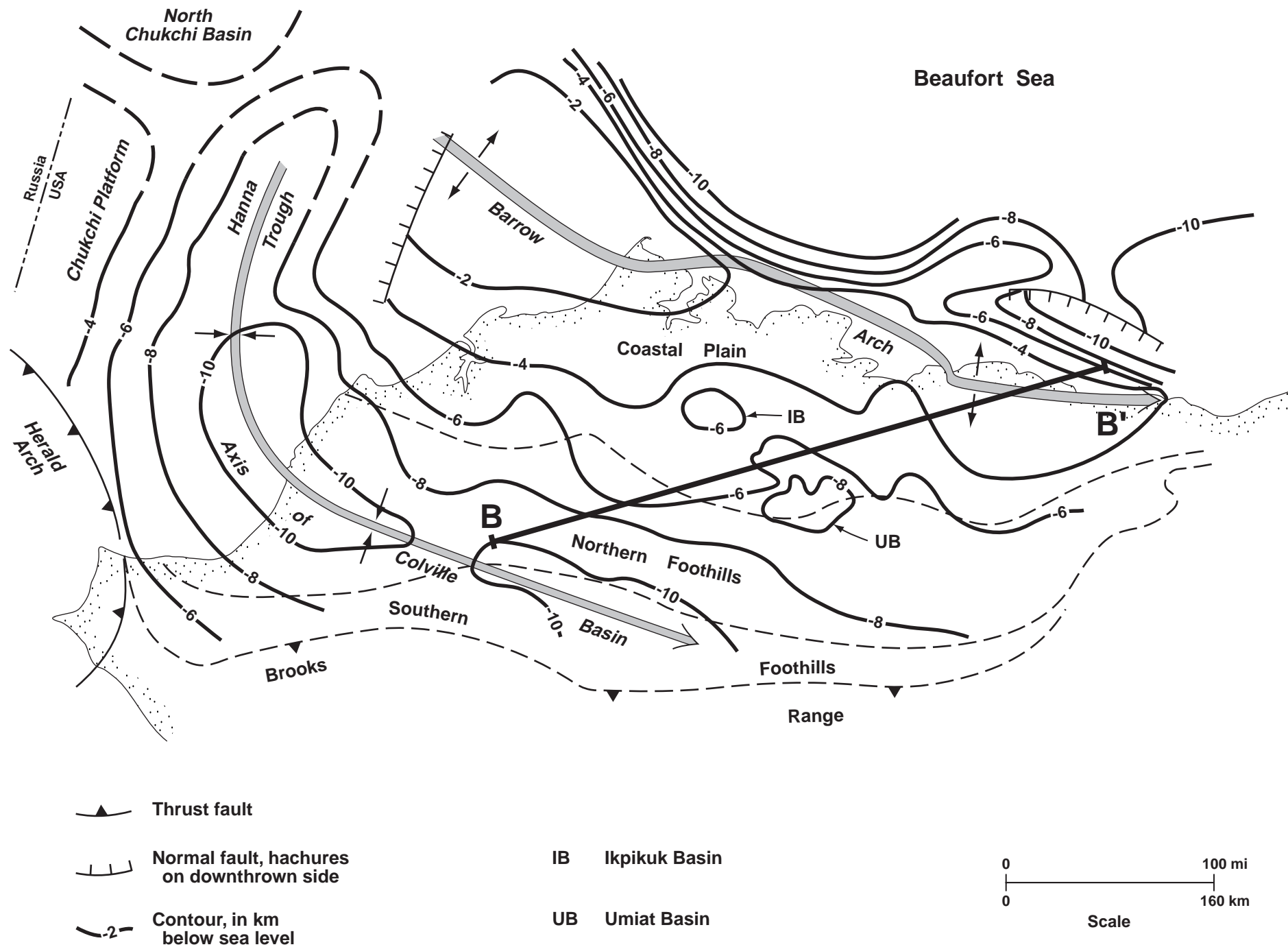


Figure 23. Structure contour map of Colville Basin and western North Slope, Alaska, showing the location of cross section B-B' (Figure 27) and depth (in kilometers subsea) to pre-Carboniferous basement rocks. This depth is roughly equivalent to a combined total Brookian and Ellesmerian System isopach. After Molenaar et al., (1988) and Bird (1991).

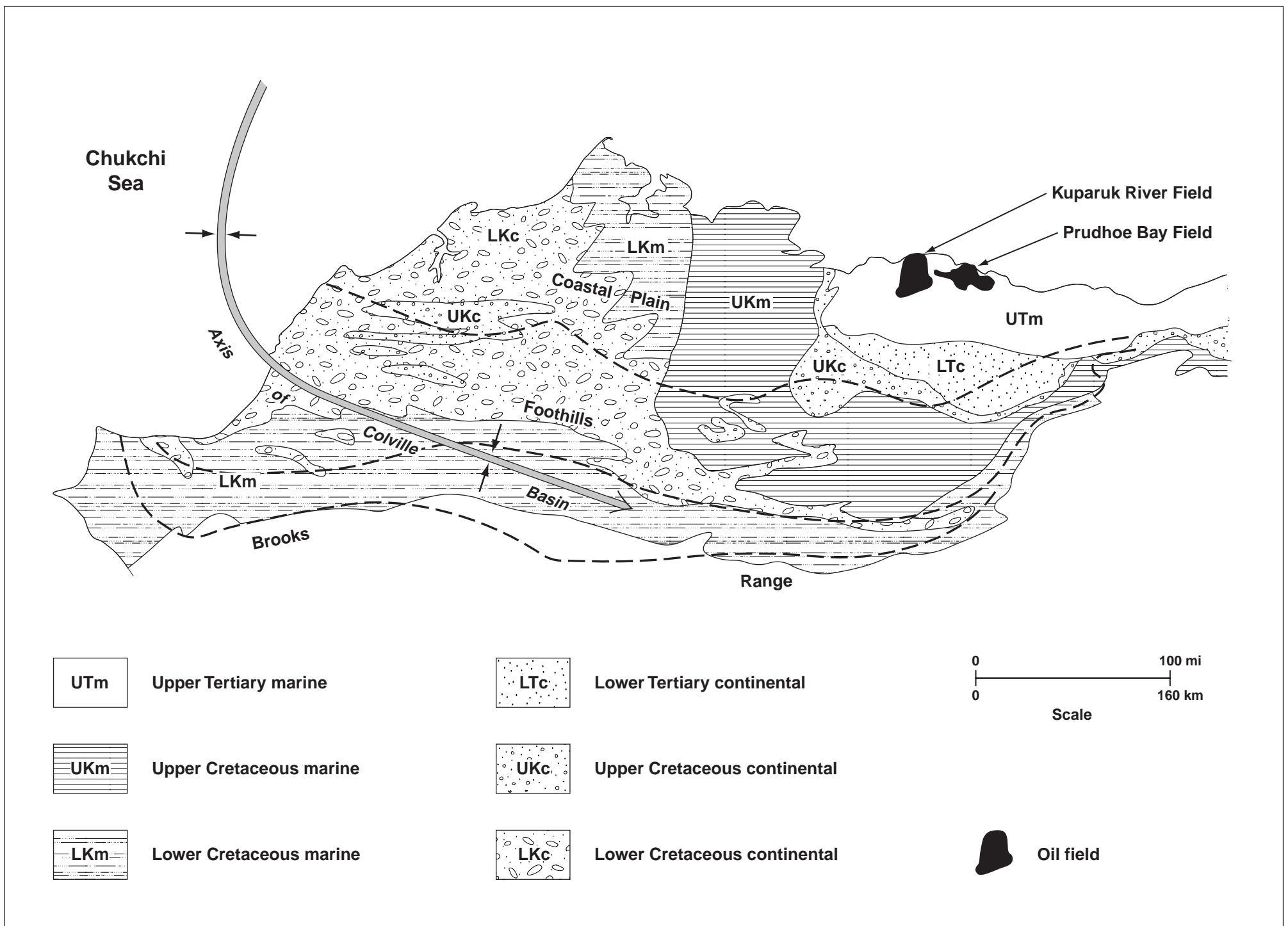


Figure 24. Geologic map of the Colville Basin and the North Slope, Alaska. After [Molenaar et al. \(1988\)](#) and [Bird \(1991\)](#).

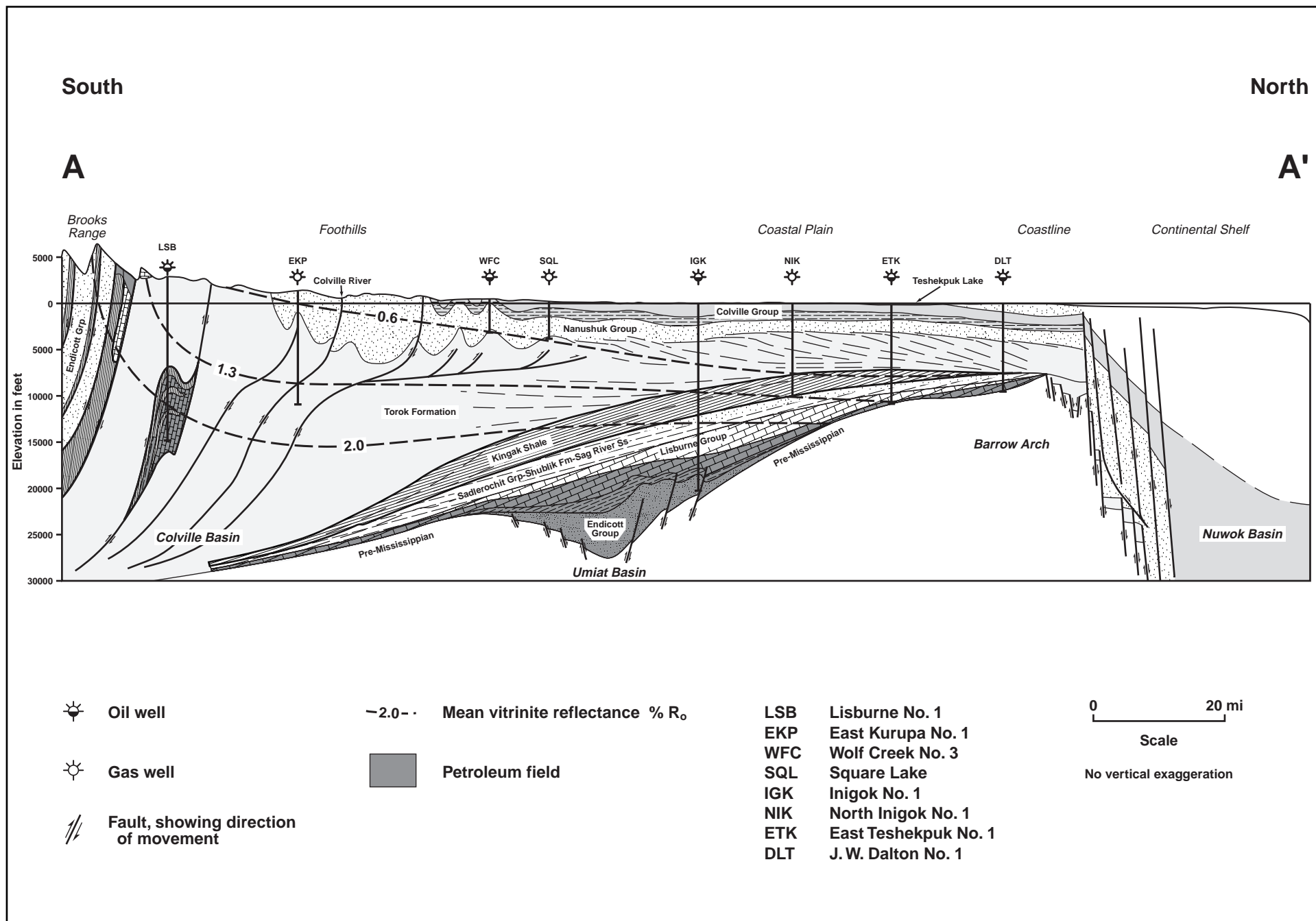


Figure 25. Cross-section A-A' across western North Slope, Alaska, including the Colville Basin (Figure 22 shows the section location). Section shows diagrammatic structure, generalized stratigraphy, petroleum fields, and wells. Vitrinite isograds show disposition of the oil window (0.6 - 1.3 % R_o) and the condensate window (1.3 - 2.0 % R_o). After Bird (1991).

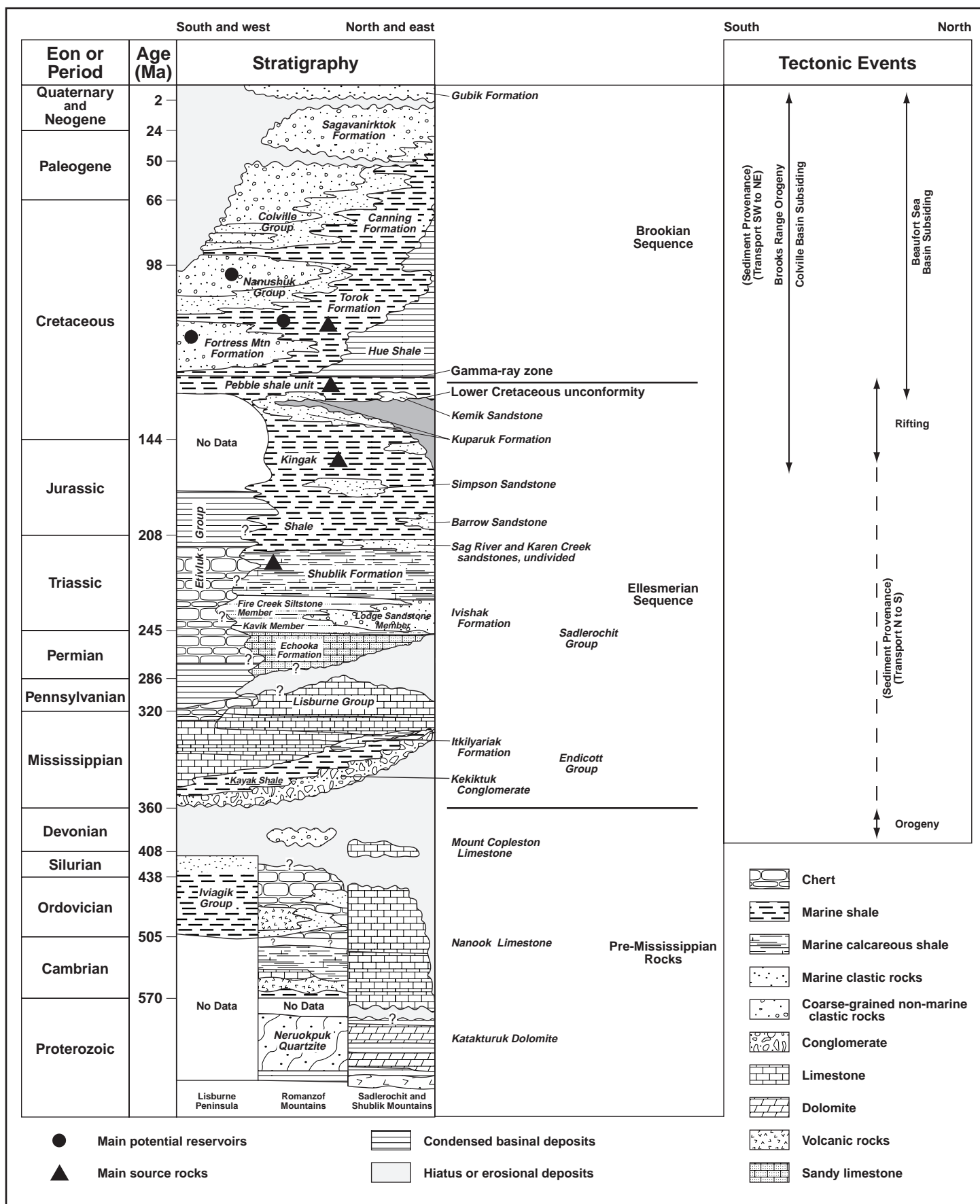


Figure 26. Generalized stratigraphic column of North Slope subterranean (Arctic Alaska terrane). Jurassic Simpson and Barrow sandstones are of local usage. Brookian sequence depicts North Slope units only; less well-known Brookian rocks in Lisburne Peninsula and northeastern Brooks Range are not shown. After Bird (1991) and Moore et al. (1994).

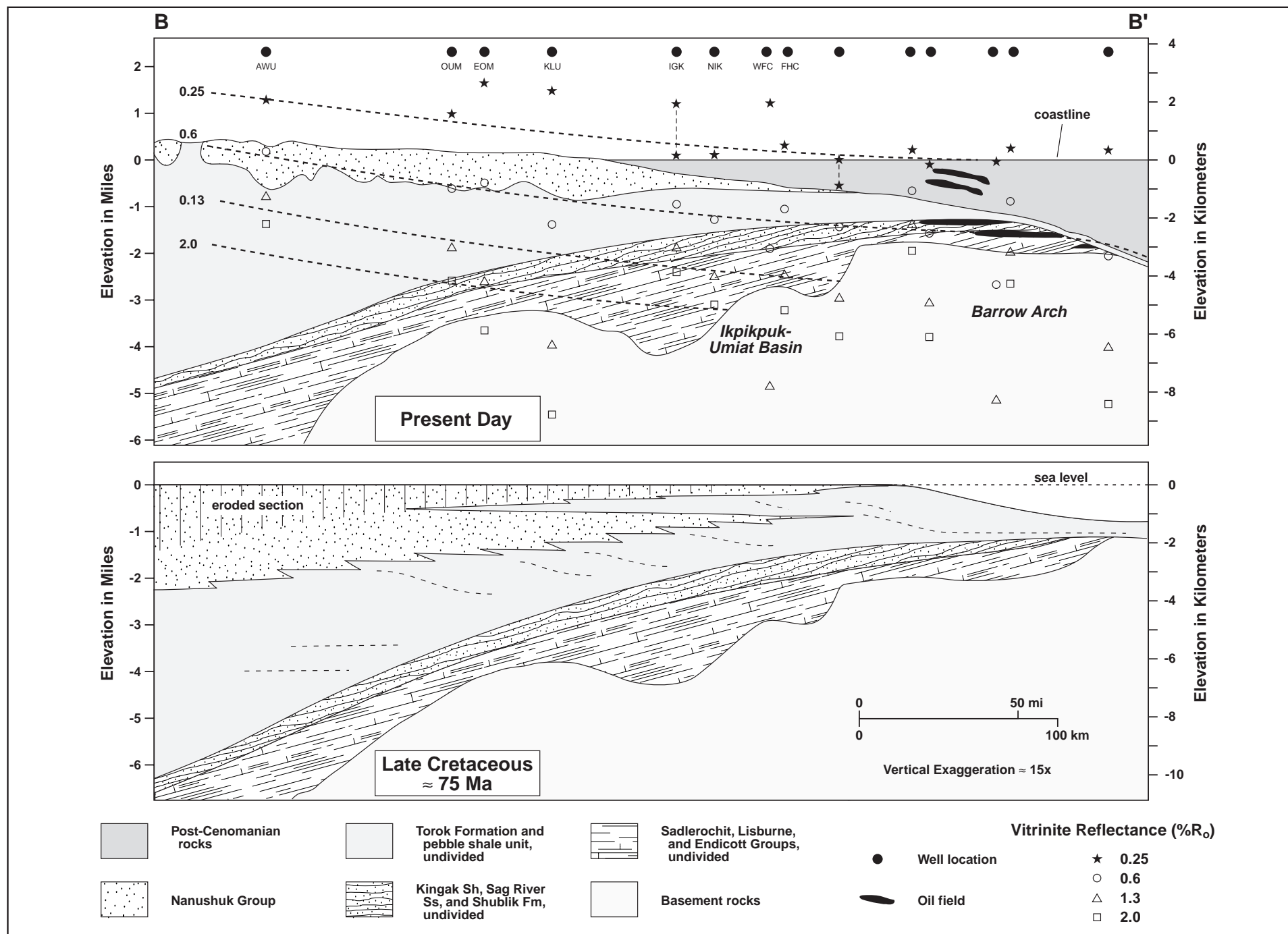


Figure 27. Present-day and Late Cretaceous cross-sections B-B' (location on Figure 23) of across Colville Basin and Barrow Arch. Upper illustration shows sampled wells (names and locations on Figure 30) and depths for vitrinite reflectance (% R_o) reference values (Bartberger and Dyman, in press).

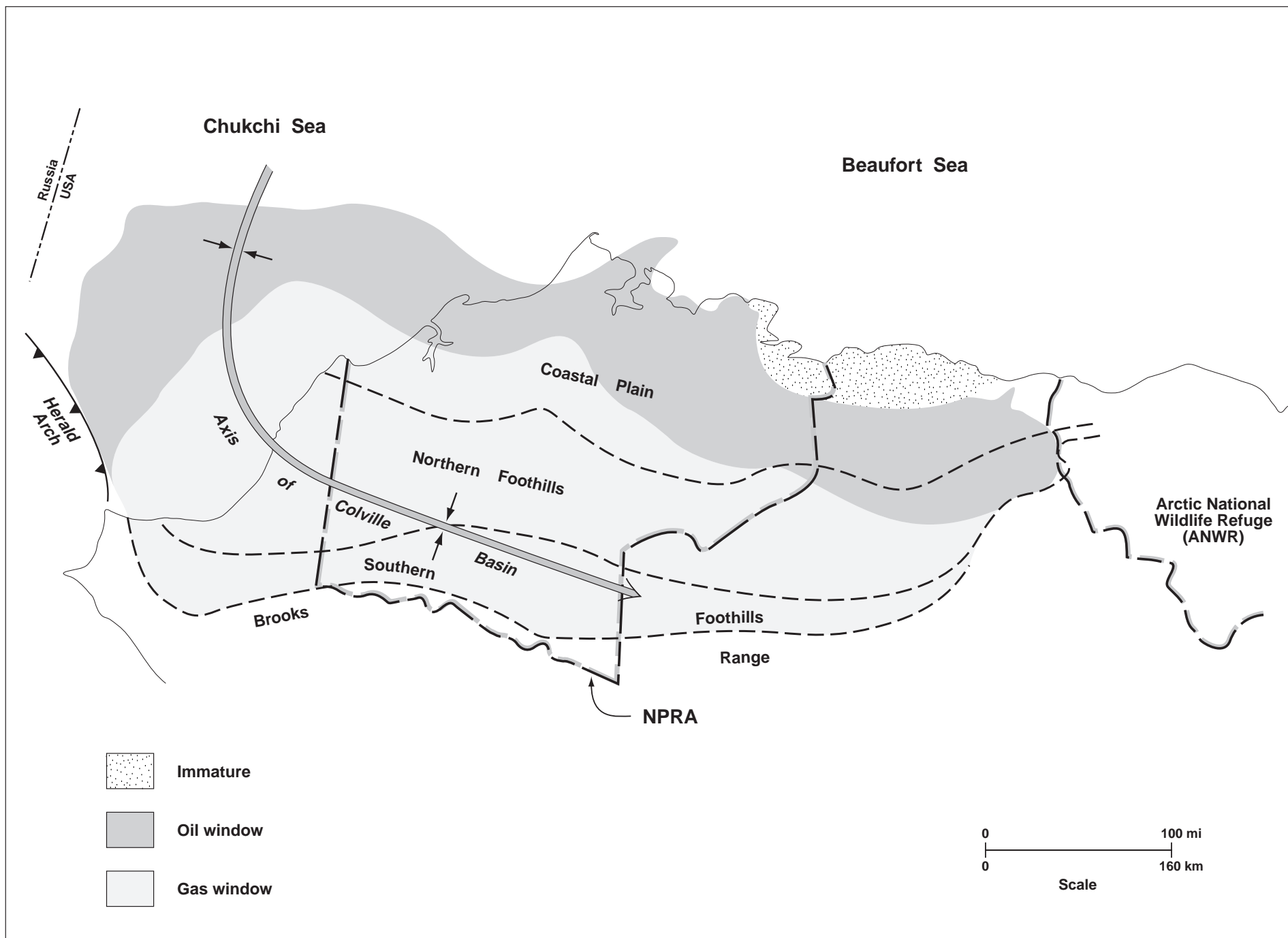


Figure 28. Thermal maturity of subsurface Shublik Formation and Kingak Shale, Colville Basin and western North Slope, Alaska. After [Molenaar et al., \(1988\)](#) and [Bird \(1994\)](#).

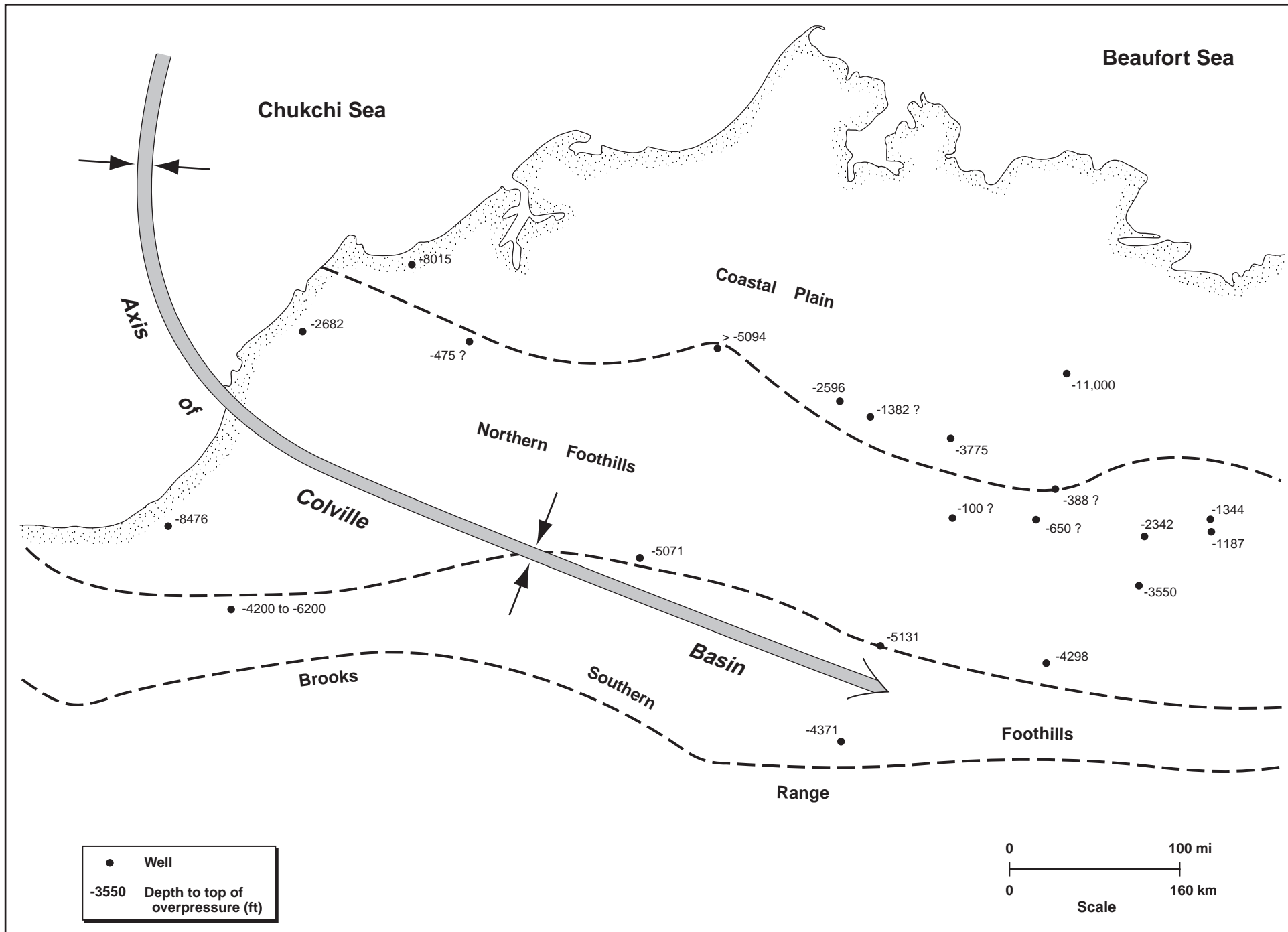


Figure 29. Map of Colville Basin showing estimated subsea depth to top of overpressure in selected wells. Data from some US Navy wells (1944-53), indicated by question marks, are suspect (see [Bartberger and Dyman, in press](#)).

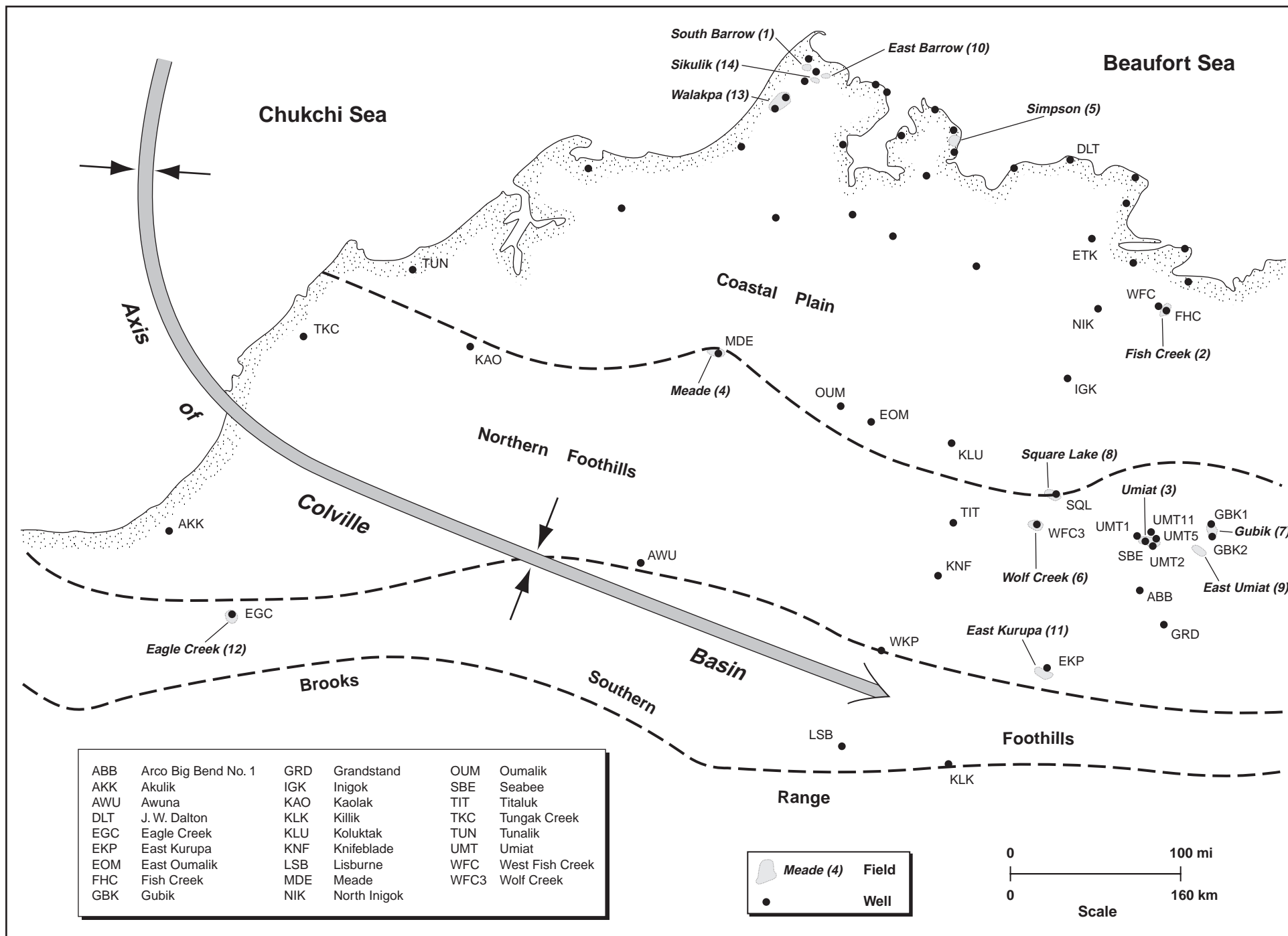


Figure 30. Map of Colville Basin and North Slope, Alaska, showing well locations and fields. After Bird (1994) and Bartberger and Dyman (in press).

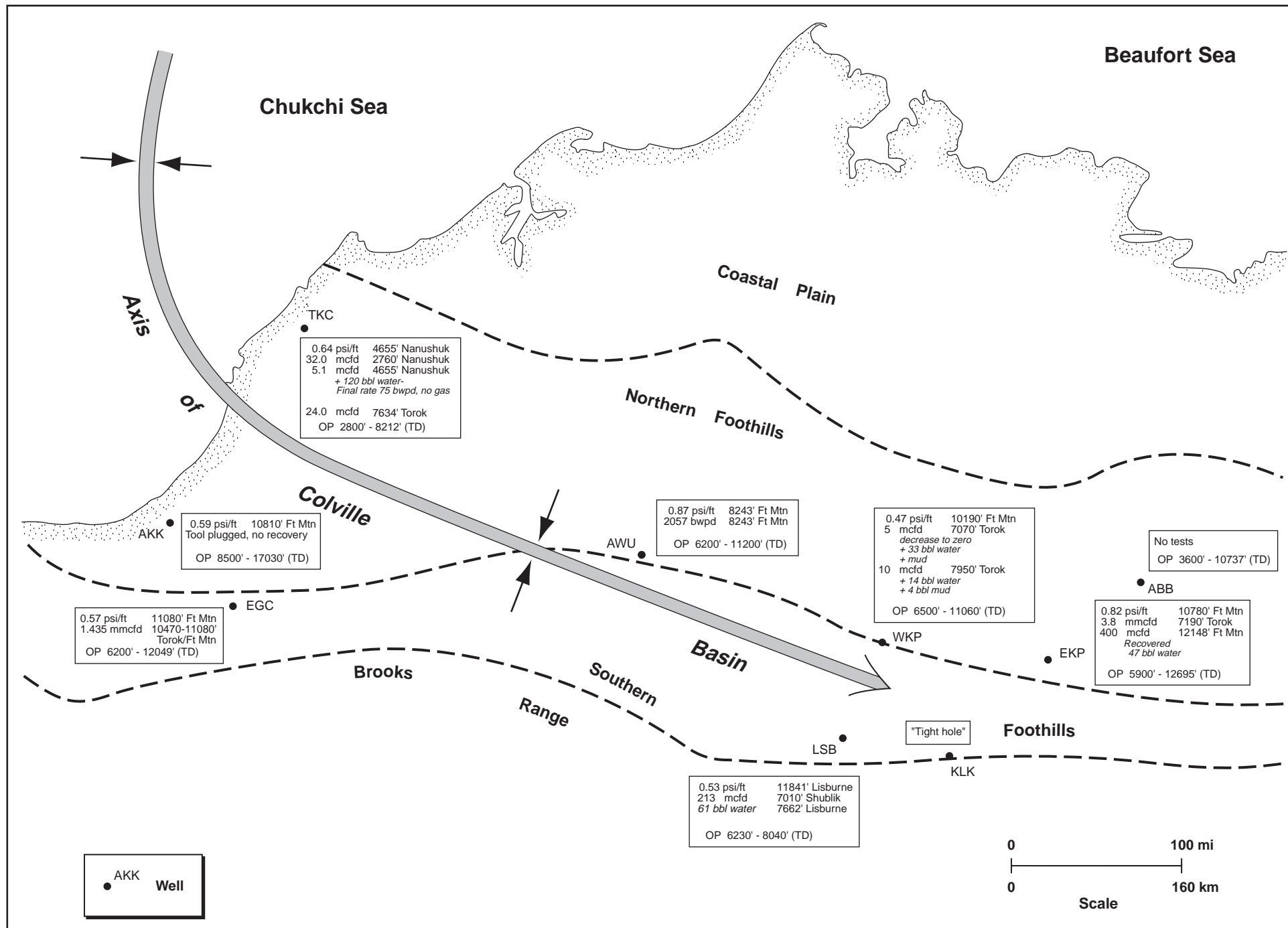


Figure 31. Map of Colville Basin, Alaska, showing fluid-pressure gradients (in psi/ft) calculated from shut-in pressures measured during drill stem and formation tests; depth of tests; stratigraphic unit tested; and summary of recovery (Bartberger and Dyman, in press).

COOK INLET, ALASKA

GEOLOGIC SETTING

The Cook Inlet basin is a narrow elongate trough of Mesozoic and Tertiary sediments, covering approximately 11,000 square miles in south-central Alaska (Figure 32). The basin trends NNE-SSW and is bounded on the northwest by granitic batholiths of the Alaska-Aleutian range and the Talkeetna mountains, and on the southeast by the Chugach terrane that makes up the Kenai Mountains (Magoon, 1994). The Border Ranges, Castle Mountain, and Bruin Bay faults are major structural features (Figure 32) (Boss et al., 1975). The Outer Continent Shelf area lies between these faults and contains anticlinal structures and faults that may be potential traps for hydrocarbons (Magoon, 1976).

Dickinson (1971) described the basin as a trench-arc gap type: a Cenozoic residual forearc basin in a convergent continental margin along the northwest Pacific Rim. Cook Inlet basin development began as a backarc basin during the Jurassic, evolving to a forearc basin in the Cenozoic (Magoon, 1994). Numerous high angle reverse faults indicate compression throughout the Mesozoic and Cenozoic.

Kelly and Halbouty (1966) estimated the maximum sediment thickness in the deepest part of the basin to be 40,000 ft. Cook Inlet sediments range in age from Upper Triassic to Recent, but consist mostly of Upper Jurassic and Tertiary rocks (Figure 33). The Middle and Upper Jurassic units are thick, but a significant mid-Cretaceous unconformity has removed the Lower Cretaceous section. Boss et al. (1975) considered the Lower Jurassic volcanic rocks to be the economic "basement."

During the Tertiary uplift and erosion occurred continuously until termination by a widespread Late Pliocene-Pleistocene orogeny. The Tertiary section is part of the Kenai Group, which is separated from the West Foreland Formation (Eocene) by a thin but widespread unconformity marked by a basal conglomerate. The Kenai Group consists of three formations: Tyonek, Beluga, and Sterling. The Tyonek Formation includes the Hemlock Sandstone Member.

HYDROCARBON PRODUCTION

The most significant hydrocarbon production in the Cook Inlet basin occurs in Tertiary rocks which reach a maximum thickness of 25,000 ft in the deepest part of the basin (Smith, 1995). These rocks consist of a thick sequence of alluvial deposits. Of the total oil produced to 1994, Magoon (1994) noted that 80% originated from the Hemlock Conglomerate, 20% from the Lower Tyonek, and minor amounts from the West Foreland Formation. Discovered resources exceed 1.2 BBO. Unassociated natural gas occurs in shallower younger reservoirs and accounts for most of the Cook Inlet gas production (Magoon and Kirchner, 1990). This gas is found in the Beluga and Sterling formations, may be biogenic, and primarily originates from Tertiary coals (Molenaar, 1996). Only minor amounts of oil have been produced from Mesozoic rocks. The Middle Chuitna Formation in the upper Cook Inlet and the Upper Triassic-Middle Jurassic rocks in the lower Cook Inlet are the source rocks for oil. Siltstones and claystones associated with coals compose the seals.

Bird (1996) identified three petroleum systems in the Cook Inlet

1. Hemlock-Tyonek oil.
2. Beluga-Sterling gas.
3. Late Mesozoic oil. This system includes Lower Jurassic to Upper Cretaceous rocks. This interval appears to be the only stratigraphic section capable of supporting a basin-centered gas play in the Cook Inlet basin.

To date, production in the Late Mesozoic has been marginal because of poor-quality reservoir rocks. Limited production has occurred from marine and turbidite sandstones within the Upper Cretaceous Matanuska and Kaguyak Formations, Lower Cretaceous sandstones, and the Upper Jurassic Naknek Formation. Lateral permeability barriers within siltstones seal these reservoirs and the reservoirs in the unconformably overlying Lower Tertiary West Foreland Formation. However, most of these fields are faulted anticlinal structures truncated by overlying Tertiary rocks. Oil was generated during Eocene and Pliocene periods (Magoon et al., 1996a).

The Tertiary section (Beluga-Sterling gas and Tyonek/Paleocene Chickaloon coals) in the upper Cook Inlet includes coals as source rocks within an area described by Molenaar (1996) as thermally immature. This area contains gas fields having localized sources. In contrast, Smith (1995) reported carbon isotope analyses of gas from coals in the Tyonek Formation that indicated both biogenic and thermogenic origins. The reported gas volumes from coals ranged from 63 standard cubic feet per ton (scf/ton) at 521 ft in depth to 245 scf/ton at 1,236 ft in depth.

EVIDENCE FOR BASIN-CENTERED GAS

Although few holes were drilled in the central trough of the Cook Inlet, limited data (mostly from the COST No. 1 well shown in Figure 32) indicates a significant increase in thermal maturity to $R_o = 0.87$ in the lower part of the Upper Jurassic Naknek Formation. Thermal maturity of Middle Jurassic source rocks ranges from immature to mature on the flanks of the basin and postmature in the deepest part of the basin (Magoon, 1994). However, conflicting interpretations place the top of the oil window ($R_o = 0.6$) at disparate depths: Magoon (1994) projects the depth at 21,000 ft in the vicinity of the Swanson River oil field (Figure 34), whereas Johnsson et al. (1993) place the oil window top at 5,000 m depth (about 16,400 ft) (Figure 35). This difference dramatically changes the basin area that may be thermally mature.

Frequent hydrocarbon shows occur within the Middle Jurassic interval. Significant variations in pressure gradients occur within the current oil and gas producing fields and flank the area of the potential basin-centered accumulation. Although this does not directly indicate pressure seals occur in the central trough of the Cook Inlet, the data suggests that lateral permeability barriers do exist within the conventionally trapped hydrocarbon accumulations. Source rocks within the Middle Jurassic Tuxedni Group indicate adequate but somewhat limited source potential (TOC content of 0.8 to 2.1 weight %). A normal geothermal gradient of 12.5 °F per 1000 ft (in the COST No. 1 well) also appears to lessen the possibility of a basin-centered accumulation at shallow depths.

Depending on the oil generation window interpretation, basin-centered gas accumulations in the Cook Inlet may potentially range in depth from less than 3,280-19,685 ft for the upper limit, to 41,891 ft for the floor.

KEY ACCUMULATION PARAMETERS

Identification

Southern Alaska, Cook Inlet basin, lower Jurassic to upper Cretaceous overpressure

Geologic Characterization of Accumulation:

- | | |
|---|---|
| a. Source/reservoir | Middle Jurassic Tuxedni group, Reservoirs - Lower Jurassic Talkeetna Fm, Middle Jurassic Tuxedni Group, Upper Jurassic Naknek Formation, and Upper Cretaceous Matanuska Formation |
| b. Total Organic Carbons (TOCs) | 0.8-2.1 weight% (Middle Jurassic Tuxedni group). |
| c. Thermal maturity | T _{max} from lower part of Naknek formation in the Cost #1 well is approximately 483° C; R _o maximum is approximately 0.87%. |
| d. Oil or gas prone | Both oil and gas prone. |
| e. Overall basin maturity | Immature to mature, anticipated to be postmature in the deepest part of the basin. |
| f. Age and lithologies | Lower Jurassic Talkeetna formation (massive volcanic conglomerates, tuffs and sandstones), Middle Jurassic Tuxedni group (marine sandstone, conglomerates, siltstones and shales), Upper Jurassic Naknek formation (shallow marine fine grained, cross-bedded sandstone) Upper Cretaceous Matanuska formation (shallow marine turbidite sandstones). |
| g. Rock extent/quality | Marginal basin wide source and variable reservoir rock distribution |
| h. Potential reservoirs | Talkeetna formation, Tuxedni group, Naknek formation and Matanuska formation |
| i. Major traps/seals | Tuxedni group |
| j. Petroleum generation/migration models | Weimer's (1996) "Cooking Pot" model with current hydrocarbon generation and relatively short distance migration. |
| k. Depth ranges | 3,280 to 41,900 ft (6 to 11 km). |
| l. Pressure gradients | Granite Point field (Tyonek formation) 0.476 to 0.503 psi; McArthur River field (Hemlock formation) 0.399 to 0.454 psi; Middle Ground Shoal field (Tyonek formation) 0.263 psi, (Hemlock formation) 0.488 psi; Swanson River field (Hemlock formation) 0.504 to 0.518 psi; Trading Bay field (Tyonek formation) 0.487 psi, (Hemlock formation) 0.261 psi. Figure 32 shows locations of gas and oil fields. |

**Production and Drilling
Characteristics:**

- a. Important fields/reservoirs** Only marginal production occurs within the Upper Jurassic Naknek to Upper Cretaceous Matanuska formations.
- b. Cumulative production**

**Economic
Characteristics:**

- a. Inert gas content**
- b. Recovery**
- c. Pipeline infrastructure** Good
- d. Exploration maturity relative to other basins**
- e. Sediment consolidation** Good to moderate consolidation.
- f. Porosity/completion problems** Low porosity because of probable clays and migrating fines.
- g. Permeability** Not available, but expected to be highly variable.
- h. Porosity** Highly variable

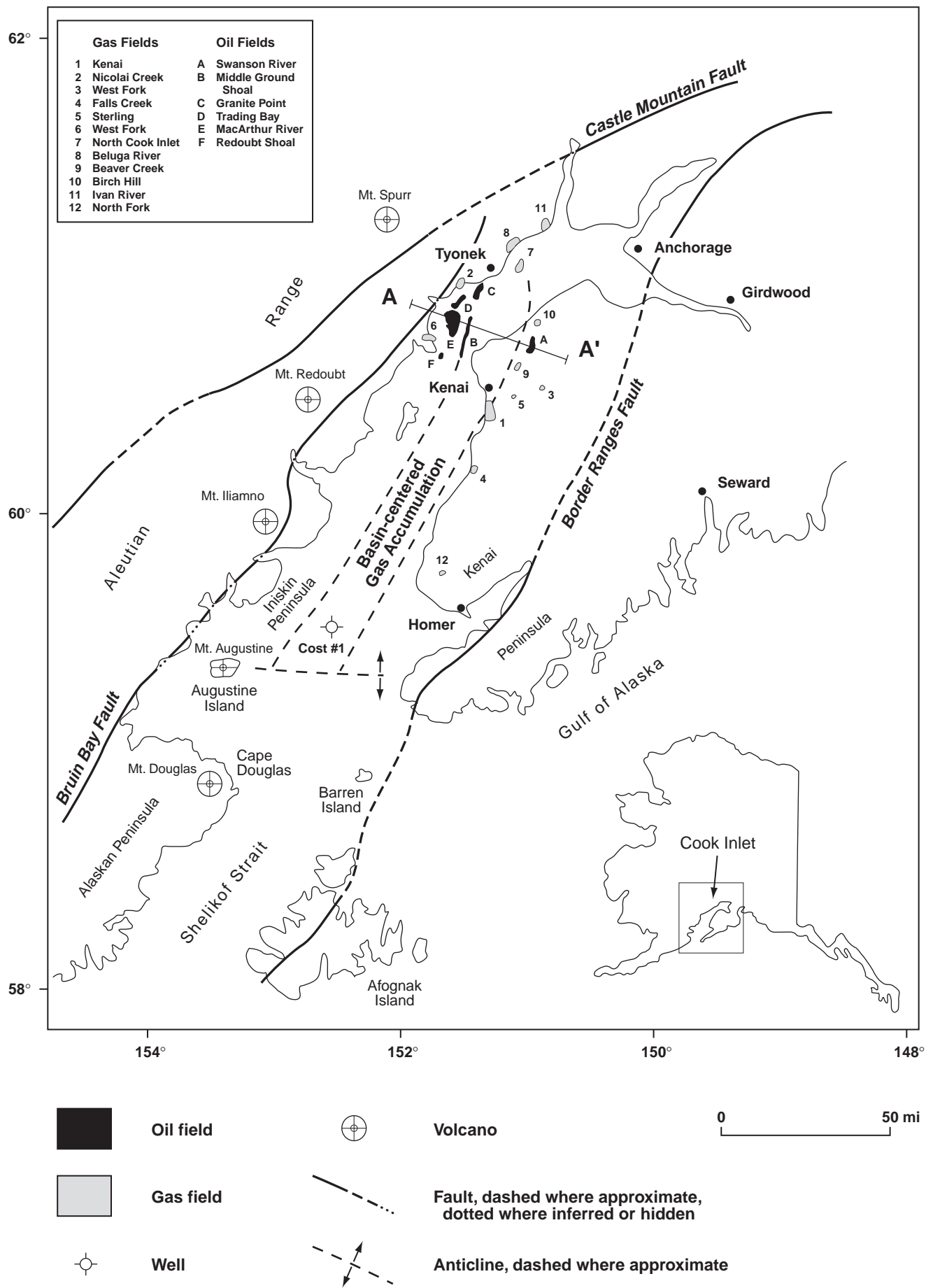


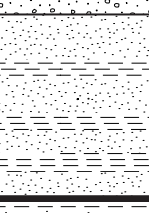



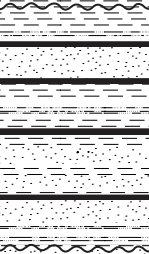











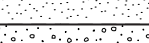




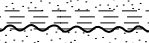



Figure 32. Map of Cook Inlet, Alaska, showing the location of cross section A-A' (Figure 34). Modified from Magoon (1976, 1994).

System	Series	Formation (thickness)	Lithology	Production	Field		Source Rock		Depositional Environment
					Oil	Gas	Oil	Gas	
Quaternary	Recent	Alluvium							Nonmarine
	Pleistocene	Glacial							
Tertiary	Pliocene	Sterling Formation (0-11,150 ft)		 		1, 2, 3, 5, 7, 8, 9			
						1, 2, 8, 9			
	Miocene	Beluga Formation (0-5900 ft)							
									
									
									
									
									
	Oligocene	Chuitna Member (1300-2600 ft)							
									
	Eocene	Middle Ground Shoal Member (2600-4900 ft)							
									
Cretaceous	Upper	Mantanuska Formation (0-8500 ft)							Marine
	Lower	Unnamed (0-1800 ft)							
		Naknek Formation (0-6900 ft)							
Jurassic	Upper	Chinitna Fm (0-2300 ft)							
	Middle	Tuxedni Group (0-9800 ft)							
	Lower	Talkeetna Formation (0-8500 ft)							
									

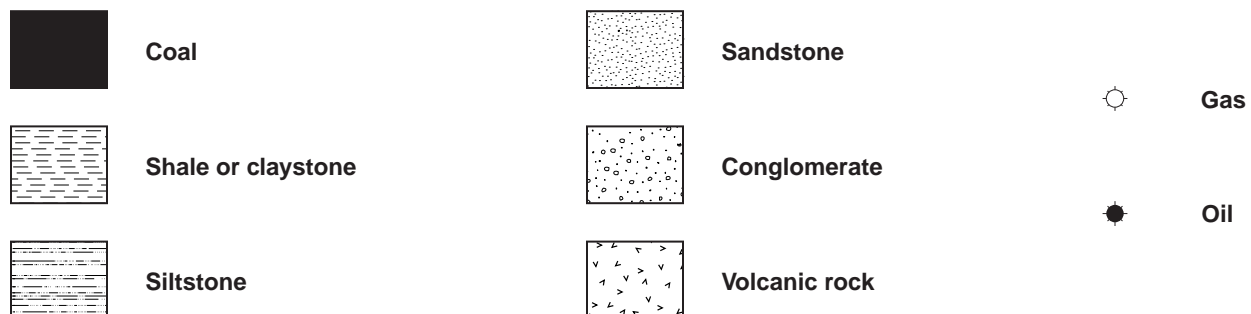


Figure 33. Generalized stratigraphic column for Cook Inlet, Alaska, showing producing intervals, oil and gas fields (noted on location map), source rock intervals, and depositional environment. After Magoon (1994).

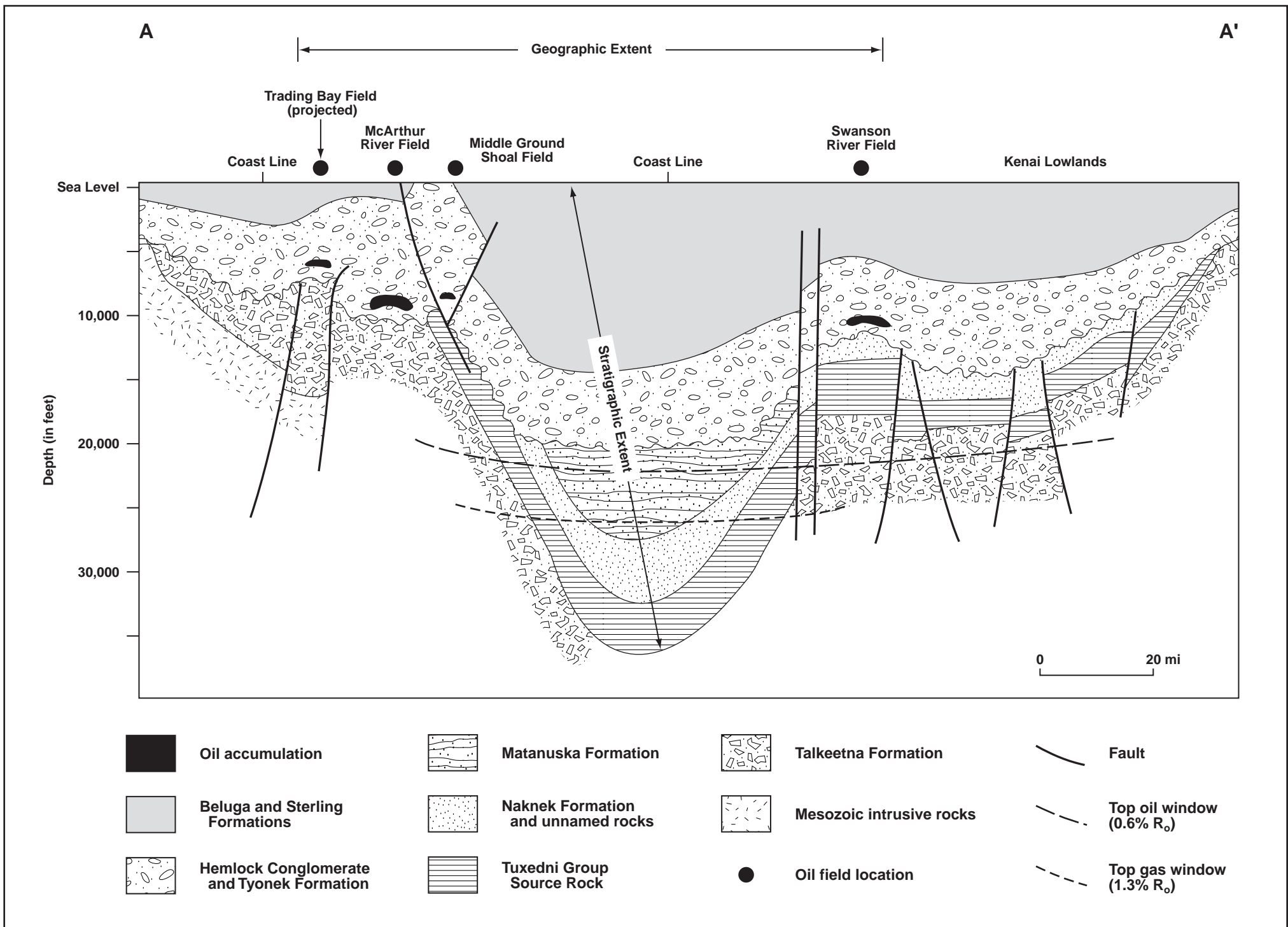


Figure 34. Cross section A-A' of Cook Inlet, Alaska, showing the geographic (horizontal) and stratigraphic (vertical) extent of the Tuxedni-Hemlock petroleum system. Figure 32 shows the location of cross section A-A'. After Magoon (1994).

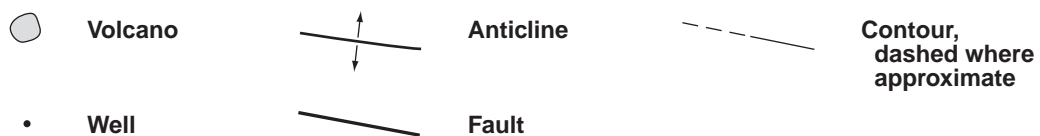
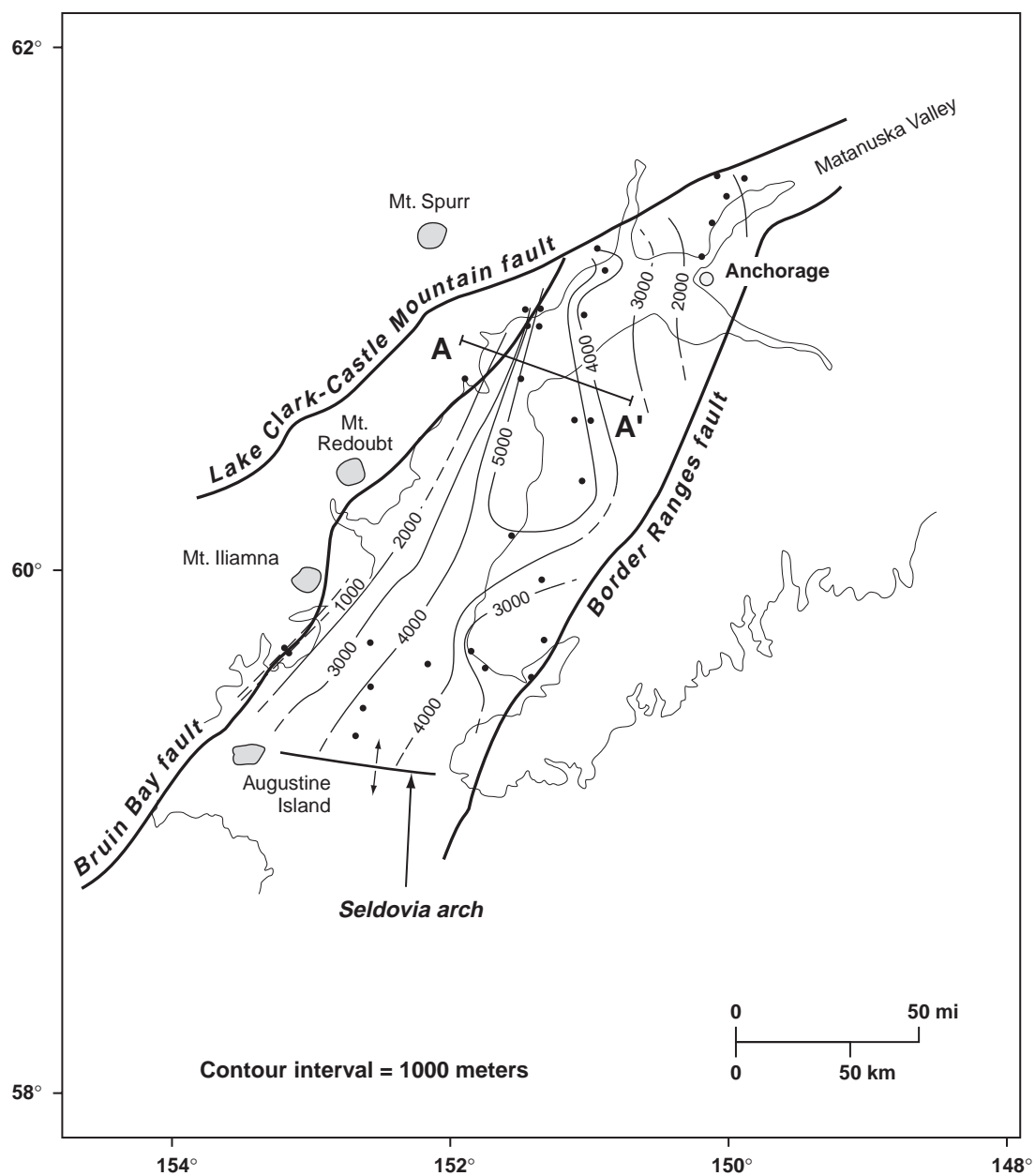


Figure 35. Contour map of the top of the paleo-oil generation window ($\%R_0 = 0.6$) in the Cook Inlet basin, Alaska. Elevation contours in meters below mean sea level. After [Johnsson et al. \(1993\)](#).

DENVER BASIN

GEOLOGIC SETTING

The Denver basin is an asymmetric crustal downwarp located mainly in eastern Colorado, western Nebraska and southeastern Wyoming. It is surrounded by the Rocky Mountain Front Range on the west, the Laramie Range to the northwest, the Hartville Uplift to the north, the Chadron Arch and Cambridge Arch to the northeast, the Yuma Uplift to the east, the Los Animas Arch to the southeast, the Apishapa Uplift to the south and the Wet Mountains Uplift to the southwest (Bookout, 1980). The basin axis runs roughly north-south from Cheyenne, Wyoming to Denver, Colorado (about 320 miles), and the basin width extends about 180 miles (Figures 36 and 37).

The basin's sedimentary section reaches a maximum thickness of 13,000 ft along the axial trend (Clayton and Swetland, 1977), and consists mostly of Cretaceous, Permian and Pennsylvanian rocks (Figure 38).

With the onset of the Laramide Orogeny in the Late Cretaceous, the ancestral Denver basin accumulated sediments that thickened westward (Figure 39). Deposition began with the Upper Cretaceous Fox Hills sandstone and continued through the Miocene (McCoy, 1953).

The present-day Denver basin has undergone a full cycle of tectonic evolution since the Cambrian: Early Paleozoic troughs became Late Paleozoic mountain ranges, and Early Paleozoic highs subsided into lows. Late Paleozoic troughs were uplifted into post-Cretaceous mountain ranges, and Late Paleozoic mountain ranges subsided into Tertiary and Recent plateaus and low relief basins (McCoy, 1953).

HYDROCARBON PRODUCTION

Cretaceous rocks are the primary strata producing petroleum (Figure 38). This interval consists mostly of deltaic and marine detrital rocks. Although oil and gas originate from a number of Cretaceous reservoirs, the Lower Cretaceous "D" and "J" sandstones account for more than 90% of the total oil and gas production of the basin" (Clayton and Swetland, 1977).

The most significant hydrocarbon production in the Denver basin occurs in the Wattenberg field, where the "J" Sandstone is the dominant producing horizon (Figure 36). As of June 1998, cumulative production from the Wattenberg field was 1.5 trillion cubic feet of gas (TCFG), 67 million barrels of oil (MMBO), and 13.3 million barrels of water (MMBW) at average depths of 7,600 ft for the "J" Sandstone and 5,100 ft for the Hygiene Sandstone (Petroleum Information Corp., 1998).

Limited oil production occurs above the "D" and "J" in the Graneros Shale, the Greenhorn Limestone, and the Codell Sandstone. Two members of the overlying Niobrara Formation yield oil—the Fort Hays and the Smoky Hill members. The fractured Niobrara strata produced significant quantities of hydrocarbons from the Berthoud field (765 MBO and 1.85 BCFG; 4.3 MBW) and the Silo field in southeastern Wyoming (8.5 MMBO and 6.8 BCFG; 3.7 MMBW) (Petroleum Information Corp., 1998).

Figure 37 shows the locations of Niobrara gas fields. Beecher Island field (1,700 ft deep, cumulative production 39.6 BCFG between 1974 and 1998) and Goodland field (900 ft deep) represent shallow Niobrara biogenic gas fields in eastern Colorado and western Kansas (Figure 37). Oil production from the Niobrara is limited to the west flank of the basin along the Colorado and Wyoming eastern mountain front (Clayton and Swetland, 1977).

EVIDENCE FOR BASIN-CENTERED GAS

Field data supports the existence of a basin-centered hydrocarbon accumulation in the Denver basin. Widespread hydrocarbon shows occur within the interval below the Hygiene sandstone (Figure 40). In the area of the Wattenberg field, Weimer (1996) reported overpressuring from the top of the Hygiene sandstone to the top of the Muddy sandstone (Figure 40). These depths conform to a vitrinite reflectance anomaly that Smagala et al. (1984) plotted at and below the Terry-Hygiene boundary (Figure 41). Geothermal gradients as high as 30°F per 1,000 ft of burial—nearly double the norm for this basin—also occur in the vicinity of the Wattenberg field (Bookout, 1980). Well data indicate that the overpressure in the Denver basin has an upper window depth of approximately 4,500 ft. This overpressured zone eventually pinches out east of the Wattenberg field.

Figure 37 shows biogenic gas fields exist east of the limit of thermally-mature Niobrara source rocks. Significant underpressuring occurs in this area with reported pressure gradients as low as 0.21 psi/ft at the Beecher Island field. Lockridge and Scholle (1978) note that Niobrara gas accumulations here are associated with low-relief anticlinal closures; thus this area has a low potential for continuous-type accumulations.

KEY ACCUMULATION PARAMETERS

Identification

Rocky Mountain, Denver Basin, early to late Cretaceous overpressure

Geologic Characterization of Accumulation:

- a. Source/reservoir** Includes Pierre Shale through Mowry Shale. "J" (Muddy) Sandstone (underpressured) is a probable target at base of overpressure zone.
- b. Total Organic Carbons (TOCs)** 0.3-10.6% (Sharon Springs member of Pierre); 1.3-2.4% (Mowry and Skull Creek shales); 5.8% maximum (Smokey Hill chalk member of Niobrara).
- c. Thermal maturity** Tmax 464 to 401° C, R_o 1.5 to R_o <0.4 (Sharon Springs); Tmax 433-439° C (Mowry and Skull Creek).
- d. Oil or gas prone** Both oil and gas prone, except near Fort Collins, where Pierre equivalent of Sharon Springs is gas prone. Mowry and Skull Creek are gas prone.
- e. Overall basin maturity** Considered to be among top Rocky Mtn basins in terms of maturity, along with the Powder River and Green River.
- f. Age and lithologies** Early to Late Cretaceous; Pierre Shale, Niobrara chalk/shale/marl, Mowry and Skull Creek shales.
- g. Rock extent/quality** Basin-wide source and reservoir-rock distribution.
- h. Potential reservoirs**
- i. Major traps/seals** Pierre Shale
- j. Petroleum generation/migration models** [Weimer's \(1996\)](#) "Cooking Pot" model
- k. Depth ranges** Wattenberg "J" avg = 7600 ft, Hygiene = 5100 ft, Silo Niobrara = 8700 ft, Beecher Island Niobrara = 1700 ft, Goodland Niobrara = 700 ft. Overpressure zone terminates at approximately 4500 ft on the east side of the basin.
- l. Pressure gradients** In the Wattenberg field area, pressure gradients reach about 0.6 psi per ft and fall to as low as 0.21 psi per ft in the Beecher Island field on the eastern flank of the basin.

**Production and Drilling
Characteristics:**

- | | |
|---------------------------------------|---|
| a. Important fields/reservoirs | Wattenberg (J Sandstone), Berthoud (Niobrara Chalk), Silo (Niobrara Chalk), Beecher Island (Niobrara Chalk). |
| b. Cumulative production | Wattenberg-"J" Sandstone, 67 MMBO, 1.5 TCFG, 13.37 MMBW; Silo field, 8.45 MMBO, 6.8 BCFG, 3.7 MMBW; Beecher Island, 0 BO, 39.6 BCFG, 37.9 MMBW; Berthoud field, 765 MBO, 1.86 BCFG, 4.3 MMBW (Petroleum Information Production Data, 1998). |

**Economic
Characteristics:**

- | | |
|---|---|
| a. Inert gas content | No high inert gas content |
| b. Recovery | Highly variable |
| c. Pipeline infrastructure | Good |
| d. Exploration maturity relative to other basins | |
| e. Sediment consolidation | Consolidation/porosity reduction occurs with depth of burial, especially in the Niobrara Chalk (Pollastro and Martinez, 1985). |
| f. Porosity/completion problems | Chalks & other tight (low permeable rocks) produce where they are naturally fractured (Berthoud field). |
| g. Permeability | Deep basin (Wattenberg area), Niobrara chalk, approx. 0.001 to 0.01 md (G.L. Nydegger, 1999, G.L. Nydegger and Associates, personal communication); eastern flank (Beecher Island field), Niobrara = 1 to 6 md. |
| h. Porosity | Deep basin (Wattenberg area), Niobrara chalk = 6.3%; eastern flank (Beecher Island area), Niobrara chalk = 39-42%. |

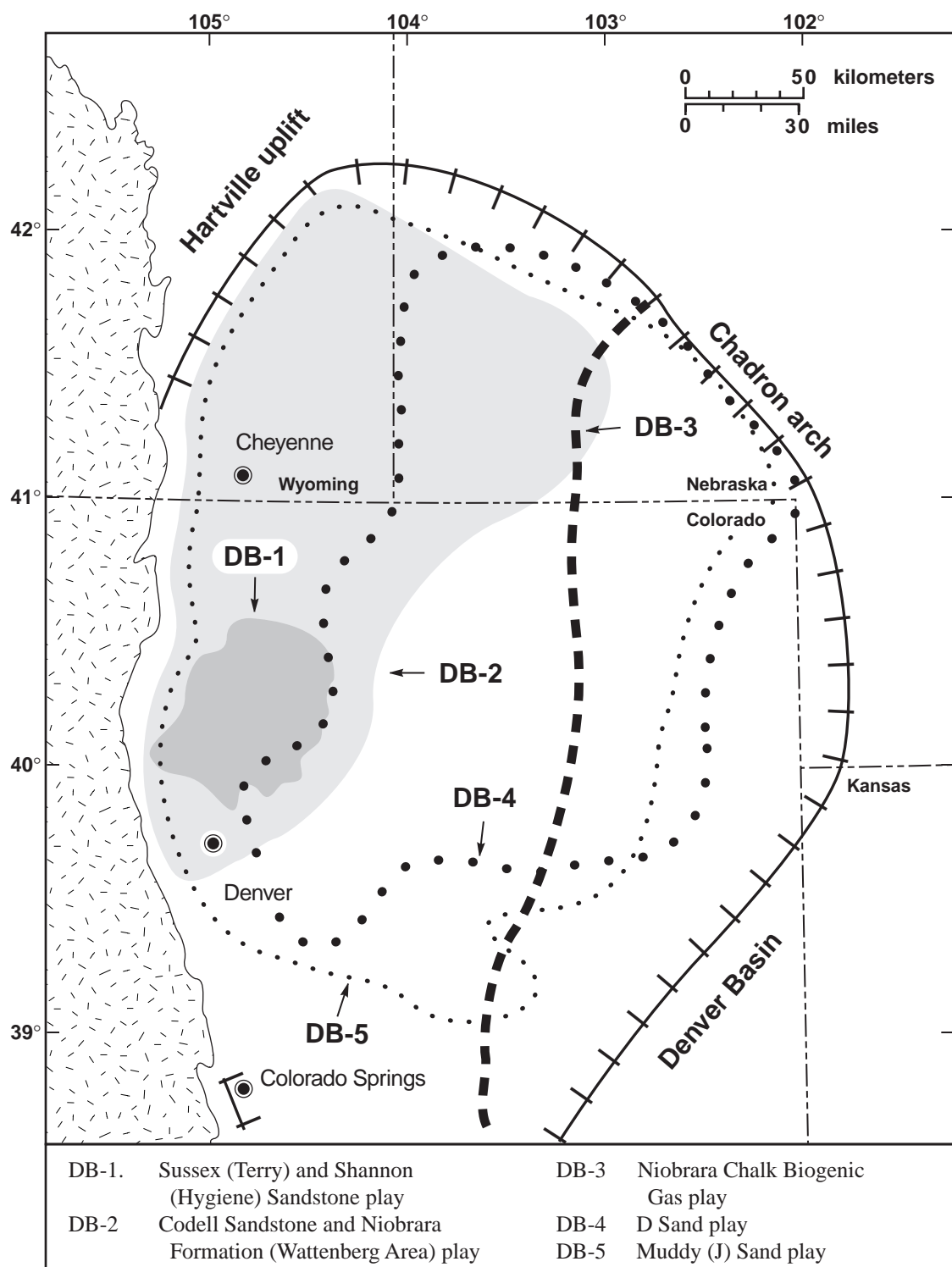


Figure 36. Index map of Denver basin showing boundaries of major (> 5 BCF) gas reservoirs. Modified from [Rice \(1984\)](#) and [Hemborg \(1993\)](#).

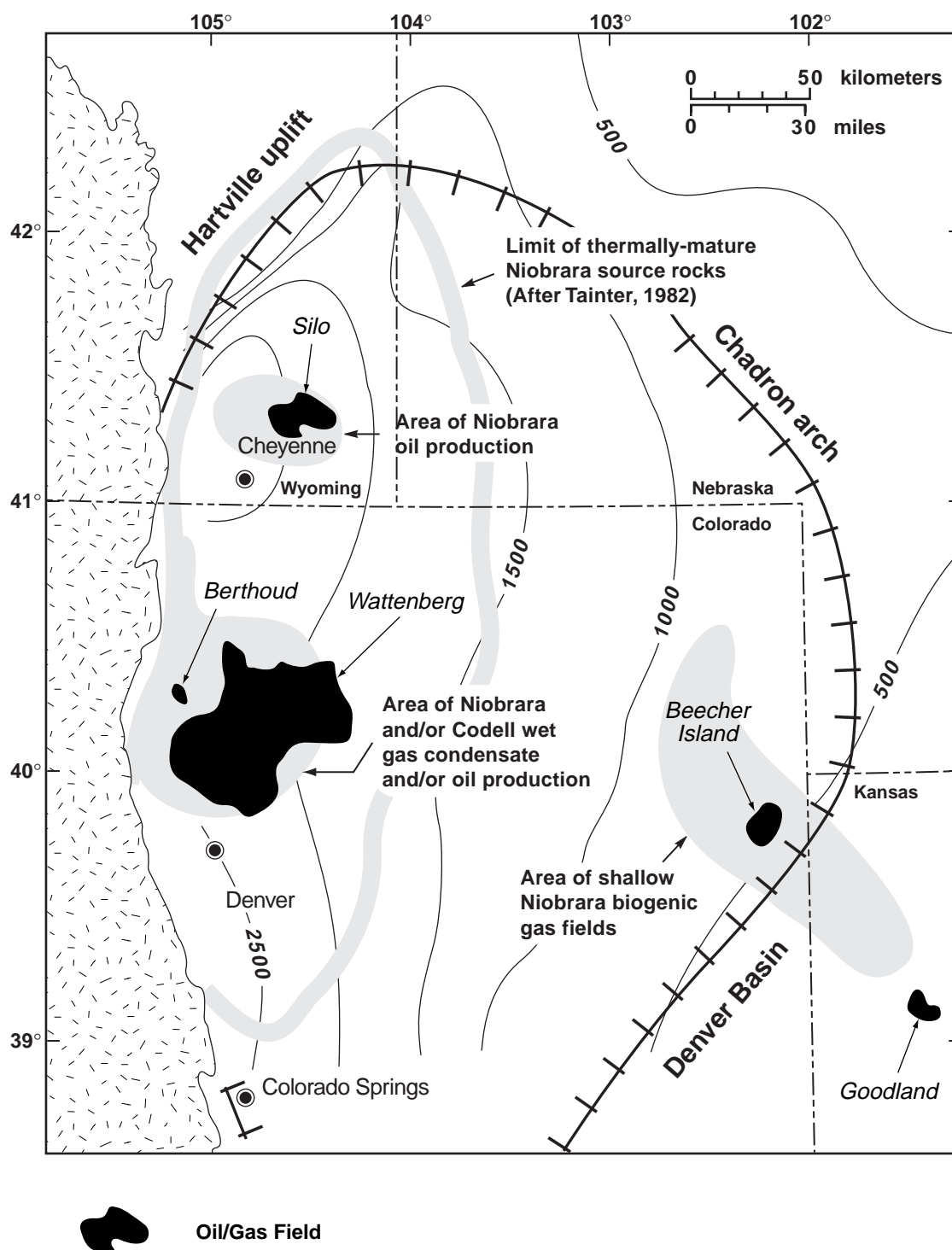










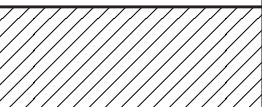



Figure 37. Index map of Denver basin showing boundaries of major (> 5 BCF) gas reservoirs. Isopachs represent depth to top of Niobrara Formation. Contour values are in meters. Modified from [Shurr \(1980\)](#); [Tainter \(1982\)](#); and [Rice \(1984\)](#).

Era	Period		Subsurface Denver Basin	Source Rock Interval	Producing Units
Cenozoic	Tertiary	Oligocene	White River Fm		        
		Eocene			
		Paleocene	Denver-Dawson Fm		
Mesozoic	Cretaceous	Upper	Arapahoe Fm		
			Laramie Fm		
			Fox Hills Fm		
			Pierre Shale		
			Richard Mbr		
			Terry Ss		
			Hygiene Ss		
			Mitten Mbr		
			Sharon Spgs Mbr		
			Niobrara Fm		
			Smoky Hill		
			Fort Hayes Ls		
		Lower	Carlile Shale		
			Codell Ss		
			Blue Hill Sh		
			Fairport Ch		
			Greenhorn Ls		
			Graneros Sh		
		Jurassic	Mowry Sh		
			Dakota Ss		
			Muddy (J) Ss		
			Skull Creek Sh		
			Plainview Ss		
			Lytle Ss		
Paleozoic	Permian	Triassic	Morrison Fm		
			Ralston Creek Fm		
			Entrada Fm		
			Jelm Ss		
	Pennsylvanian	Mississippian	Lykins Ss		
			Lyons Ss		
			Ingleside Fm		
			Virgilian		
			Fountain Fm		
					



Primary oil reservoir



Secondary oil reservoir

Figure 38. Geologic Column of Denver Basin. After [Hemborg \(1993\)](#).

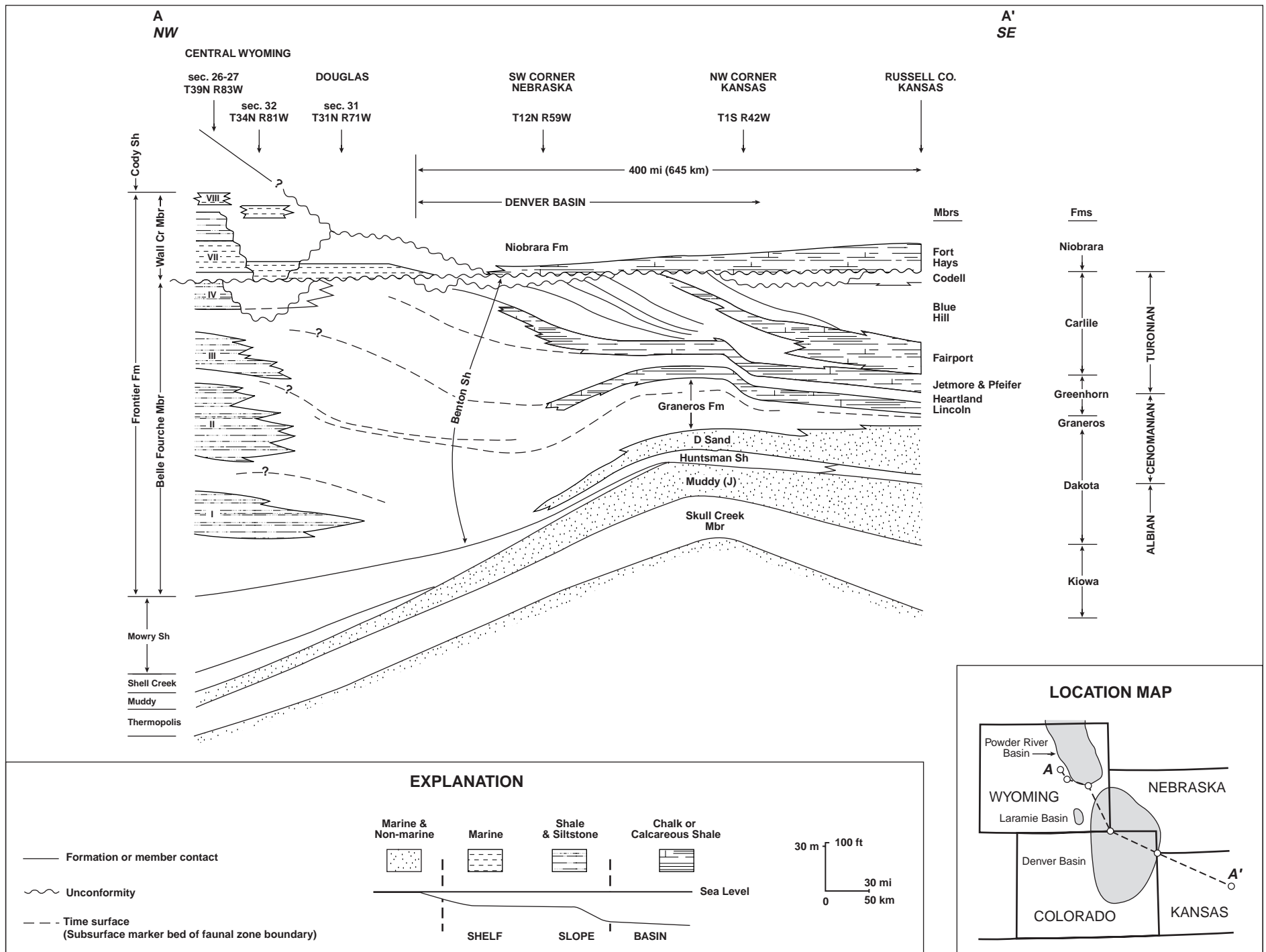


Figure 39. Restored stratigraphic cross section for D Sandstone and associated units from central Wyoming to central Kansas. After [Weimer \(1983\)](#).

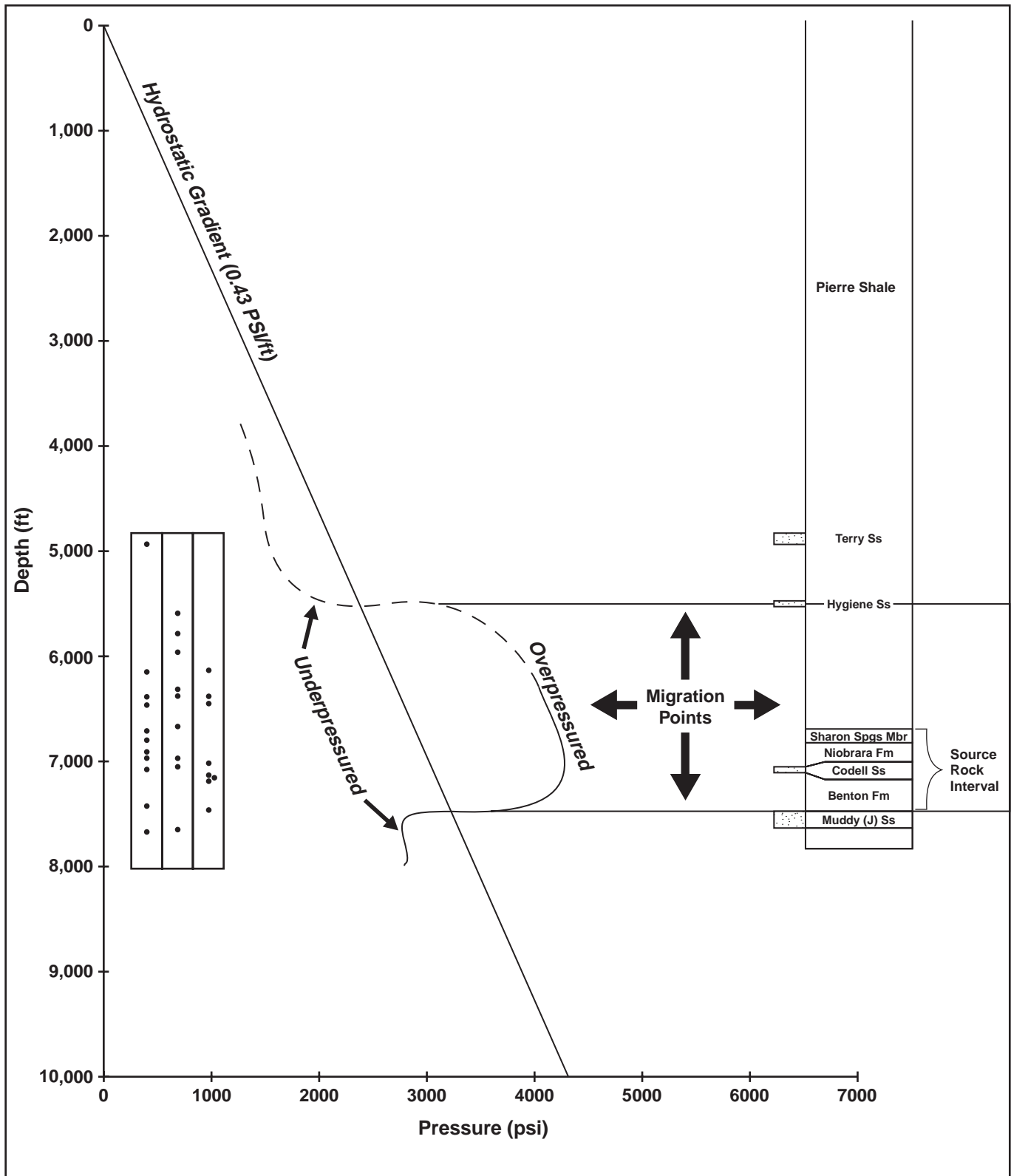


Figure 40. Pressure plot for township T 3 N, R 65 and 66 W, and T 5 N, R 65 W. Dots indicate the stratigraphic level in wells for which pressure data are available. After [Weimer \(1996\)](#).

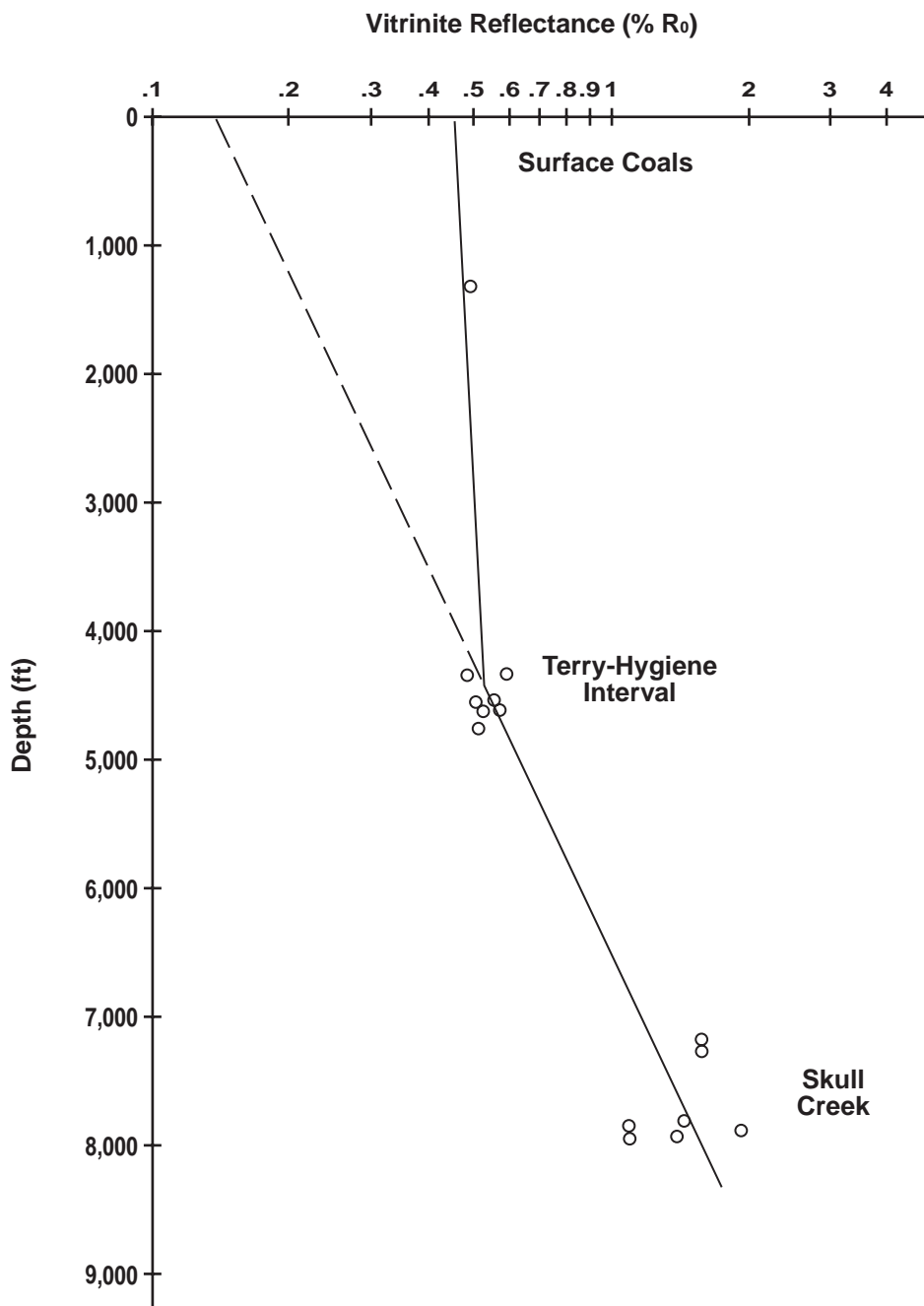


Figure 41. Plot of vitrinite reflectance versus depth from well and surface coal data (Wattenberg field area), showing dogleg maturation profile. After [Smagala, et al. \(1984\)](#).

GREAT BASIN (TERTIARY BASINS)

GEOLOGIC SETTING

The Great Basin is part of the Basin and Range geologic province, which makes up most of Nevada. [Figure 42](#) shows the valleys in the province. The state has undergone complex geological and structural development. At least four major orogenies affected the area prior to the initiation of Basin and Range extension during the Miocene ([Montgomery, 1988b](#)). Uplift during the Antler orogeny (Late Devonian to Early Mississippian) created a north-south trending barrier, isolating a foreland basin to the east. Next, the Sonoma Orogeny (Late Permian through Early Triassic) emplaced the Golconda Allochthon in central Nevada. The Jurassic Nevadan Orogeny involved thrusting and folding in the central part of the state and ended the marine sedimentation. The Sevier/Laramide episode (Late Jurassic through the Eocene) resulted in extensive volcanism throughout much of western and central Nevada, and creation of the Rocky Mountain Thrust Belt. Another period of extensive volcanism began in the Oligocene.

During the Paleozoic era and ending in the Permian, up to 50,000 feet of shallow water carbonate and clastic rocks were deposited ([Peterson, 1988](#)). From the Cretaceous through the Eocene, large lakes formed in the Black Rock Desert area and in the Carson Sink ([Figure 42](#)) and organic-rich rocks were deposited, including the Sheep Pass Formation (Late Cretaceous–Eocene), the Newark Canyon Formation (Late Cretaceous), and the Elko Formation (Eocene–Oligocene). In southeast and northwest Nevada, large lakes formed during Miocene and Pliocene time ([Barker, 1996a](#); [Hastings, 1979](#)). These lakes contain organic rich source rocks. [Figure 43](#) shows stratigraphic columns for two areas in eastern Nevada.

Crustal extension began in the Miocene, forming characteristic Basin and Range structures: alternating horsts and grabens ([Peterson, 1988](#)). Extensional faulting continues to the present. Block faulting broke up the Sheep Pass, Newark Canyon and Elko Basins. Their lacustrine and clastic fluvial deposits subsided into deep grabens. [Figure 44](#) shows a cross section across Railroad Valley in east-central Nevada. Several present day valleys contain over 10,000 feet of late Tertiary and Pleistocene fluvial, lacustrine and volcanic valley fill ([Peterson, 1988](#)). These Tertiary lacustrine deposits provided the source rock for several oil fields in Nevada. The Sheep Pass Formation provided both source and reservoir strata for Eagle Springs Field and source rocks for Trap Springs Fields in Railroad Valley ([Figure 43](#)).

HYDROCARBON PRODUCTION

There are 12 producing oil fields in Nevada at present. Reservoirs include the Garrett Ranch Volcanics, which produce at Trap Springs Field, and the Sheep Pass Formation, which produces at Eagle Springs Field. Most exploration has been along the faulted valley margins.

All deep Tertiary basins will probably have at least one good source rock either in the basin, or subcropping against the basin fill. [Barker \(1996a\)](#) states that Tertiary lacustrine shales and marls from six wells in the Carson Sink have a TOC range from 0.1 to 3.0%. The rocks have a hydrogen index over 400 mg/gram organic carbon and are oil prone. There is unusually high heat flow in the area. Strata buried only 3,300 to 6,600 ft deep during the Pliocene may now be in the oil generation window.

EVIDENCE FOR BASIN-CENTERED GAS

Gas shows have occurred in many exploration wells, indicating some of these basins have generated gas. Deep source rocks in the grabens probably lie on the gas-only generation window, because of high geothermal gradients.

The Tertiary Sheep Pass, Newark Canyon and Elko Formations are considered the most prospective for hydrocarbon generation, migration and trapping (Figure 43). There are other hydrocarbon source rocks in Nevada, including the Mississippian Chainman Shale, which in Railroad Valley is a partial source for the Eagle Springs Field and the main source for the Grant Canyon Field. These pre-Tertiary source rocks may have helped charge possible basin-centered gas accumulations within the Tertiary graben valley fill.

Regional gravity data show several basins that contain thick Tertiary fill. The valley fill is less dense than the older Paleozoic and Mesozoic strata that crop out in the bordering mountain ranges and form the basement in the grabens. Jachens and Moring (1990) published gravity maps that show the thickness of Tertiary strata. Figure 45 shows areas with pronounced residual gravity minima that may indicate thick Tertiary strata.

Several valleys in east-central Nevada have anomalously low gravity (Jachens and Moring, 1990). Tertiary lacustrine valleys are the most prospective for basin-centered gas. Their basin configurations are better known from seismic data than are other Basin and Range valleys. Some valleys fall within a gravity low, but are not in eastern Nevada and so remain speculative for basin-centered gas.

The Carson Sink in Western Nevada does not fall within a gravity low, but seismic data indicates 11,000 ft of Tertiary fill, including organic-rich lacustrine source rocks (Barker, 1996a), and several exploration wells have gas shows.

KEY ACCUMULATION PARAMETERS

Identification

Basin and Range Province; Cenozoic Speculative Basin Centered Gas Accumulation

Geologic Characterization of Accumulation:

a. Source/reservoir

Organic-rich Tertiary lacustrine shales: Sheep Pass Fm (Paleocene-Eocene), Elko Fm (Paleocene), and Newark Canyon Fm (Cretaceous); several Paleozoic source rocks may also contribute hydrocarbons to this play

([Peterson, 1988](#)): Chainman Shale (Mississippian), Pilot Shale (Upper Dev. - Lower Miss.), Carbon Ridge Fm (Permian); Webb Fm (Miss.), Woodruff Fm (Devonian), Slaven Chert (Devonian), and Vinini Fm (Ordovician)

All deep Tertiary basins will probably have at least one good source rock either in the basin, or subcropping against the basin fill. [Barker \(1996a\)](#) states that Tertiary lacustrine shales and marls from 6 wells in the Carson

Sink have a TOC range from 0.1 – 3.0%. The rocks have a hydrogen index over 400 mg/gram organic carbon and are oil prone. There is unusually high heat flow in the area. Strata buried only 1 to 2 km deep during the

Pliocene may now be in the oil generation window.

b. Total Organic Carbons (TOCs)

[Poole and Claypool \(1984\)](#) report the following TOC values:

Source	System or Series	Total Organic Carbon (TOC) (%)
Sheep Pass Fm	Paleocene - Eocene.....	3 - 4 avg, to 9.5 max
Elko Fm	Eocene - Oligocene (?).....	33.5 - 38.8 (oil shale)
Newark Canyon Fm	Cretaceous.....	to 5.66
Chainman Shale	Mississippian.....	2.3 - 3.84 avg, to 10.6 max
Pilot Shale	Upper Dev. - Lower Miss.	
Carbon Ridge Fm	Permian	
Webb Fm	Mississippian.....	to 6.12
Woodruff Fm.....	Devonian.....	5.7 avg to 13.9 max
Slaven Chert.....	Devonian.....	
Vinini Fm	Ordovician.....	1 - 25
Carson Sink.....	Tertiary.....	0.1 - 3

c. Thermal maturity

The discovery of 12 producing oil and gas fields in Nevada, indicates that there are source rocks at depth which have generated hydrocarbons. In Railroad Valley, [Poole and Claypool \(1984\)](#) interpret thermally mature

conditions below 6,800 feet – extending from Eocene Sheep Pass Fm downward into the Mississippian Chainman Shale. Overmature source rocks are most likely to be a problem in the deepest parts of this play which may

have a Paleozoic source rock. For Eagle Springs Field, the initial BHT (Bottom Hole Temperature) was 200° F (93° C) at 6400 ft. The temperature gradient is 20 deg/1000 ft for the depth interval 6000 – 10,000 ft ([Bortz and](#)

[Murray, 1979](#)). The Carson Sink has a geothermal gradient of 25 deg/ 1000 ft ([Hastings, 1979, p. 520](#)).

d. Oil or gas prone	Most exploration has been along the faulted valley margins. These areas have produced primarily oil. No drilling has been attempted to evaluate into the deepest parts of these Tertiary Basins, which may be gas prone, because of higher temperatures. The oil prone source rocks (Sheep Pass, Chainman Shale) may be buried within the dry gas window. Previously generated oil may be cracked into gas, creating possible basin-centered accumulations.
e. Overall basin maturity	
f. Age and lithologies	In the Railroad and White River Valley areas, the most likely exploration targets are the Garrett Ranch Volcanics, which produce at Trap Springs Field, and the Sheep Pass Fm. (Paleocene – Eocene) which produces at Eagle Springs Field. Paleozoic formations which subcrop against the Tertiary formations may provide additional reservoirs.
g. Rock extent/quality	
h. Potential reservoirs	Garrett Ranch Volcanics, Sheep Pass Formation
i. Major traps/seals	Traps may be of all types: structural, stratigraphic, or a combination of both. For a basin-centered gas accumulation, the trap/reservoir may cross formation boundaries.
j. Petroleum generation/migration models	The Weimer (1996) “Cooking Pot” model, where generated hydrocarbons are expelled into surrounding reservoir rocks.
k. Depth ranges	Depth will vary, because hydrocarbon generation depends on both time and temperature. Subsurface temperatures where high will positively influence hydrocarbon generation in some areas. Variability of temperature and source rock richness will make predicting depth and location difficult.
l. Pressure gradients	Eagle Springs Field has a “normal” pressure gradient of 0.4347 psi/ft (Bortz and Murray, 1979, p. 453).

Production and Drilling Characteristics:

a. Important fields/reservoirs	Eagle Springs and Trap Springs (Figure 45); Grant Canyon, and Blackburn Fields. Only Grant Canyon Field has no production from a Tertiary reservoir.
b. Cumulative production	

Economic Characteristics:

a. Inert gas content	Possible, but unknown.
b. Recovery	unknown

- c. Pipeline infrastructure** There are no gas pipelines through the Eastern play area. A 16-inch natural gas pipeline enters Nevada just east of the Oregon border and runs southwest through Winnemucca and then along Interstate Highway I-80, through the northern part of the Carson Sink Basin to Reno. The pipeline continues through Carson City, then exits Nevada into California. An 8-inch trunk line runs east to Elko from Winnemucca, and a second 8-inch trunk line runs east from north of Reno, along Highway US 50 to Frenchman.
- d. Exploration maturity relative to other basins** Although there are presently 12 producing oil fields in Nevada, the state is still a high-risk, under-drilled immature exploration area.
- e. Sediment consolidation** Unknown, but poor consolidation has not been a serious problem in wells drilled through the Tertiary section.
- f. Porosity/completion problems** Unknown, low porosity and fracture production are expected in this play, both of which may cause drilling and completion problems.
- g. Permeability**
- h. Porosity**

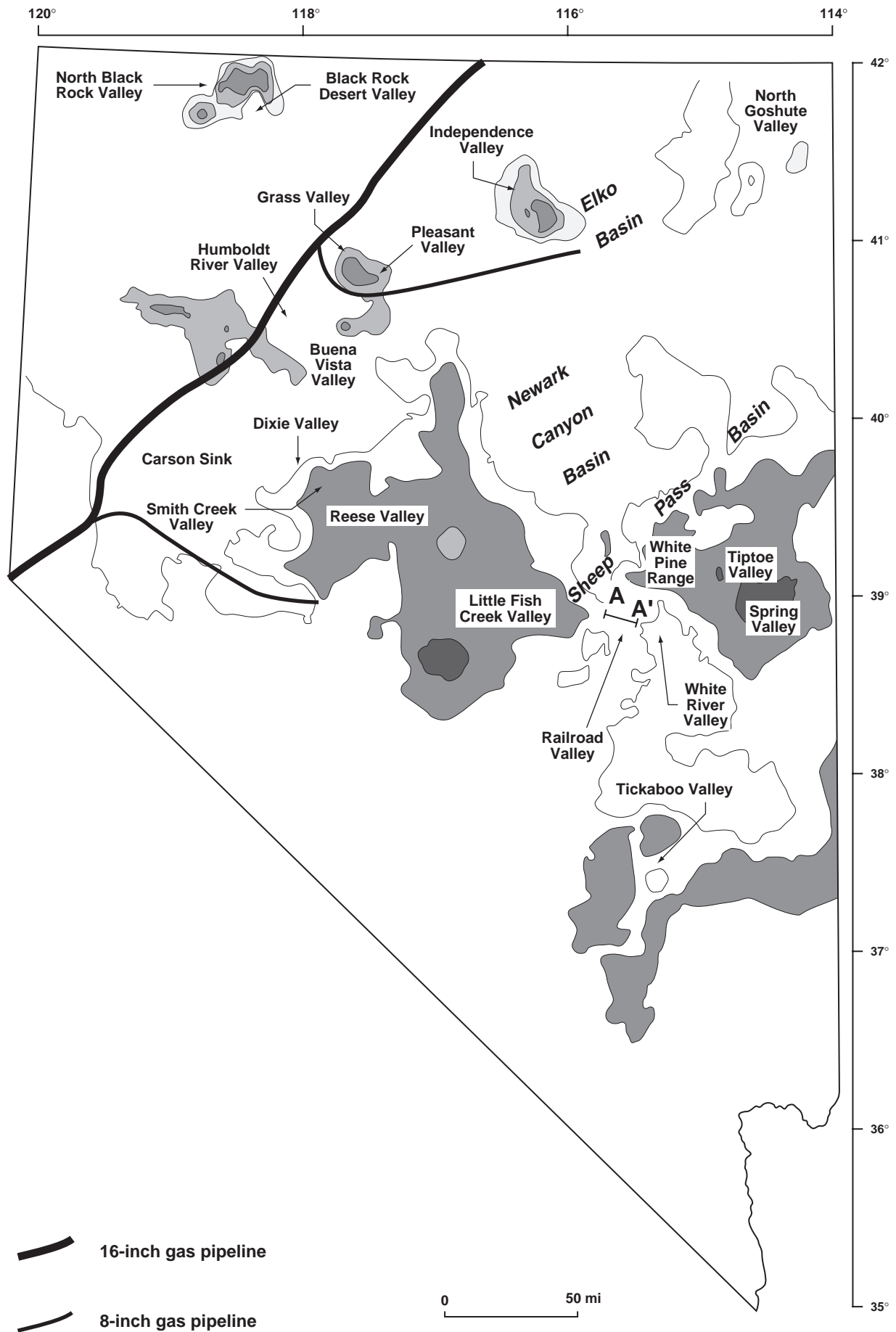


Figure 42. Map of Nevada showing grabens/valleys of the Basin and Range Province, and locations of cross section A-A' (Figure 44) and existing pipelines. After Peterson (1988; 1994b) and Penwell Publishing (1990).

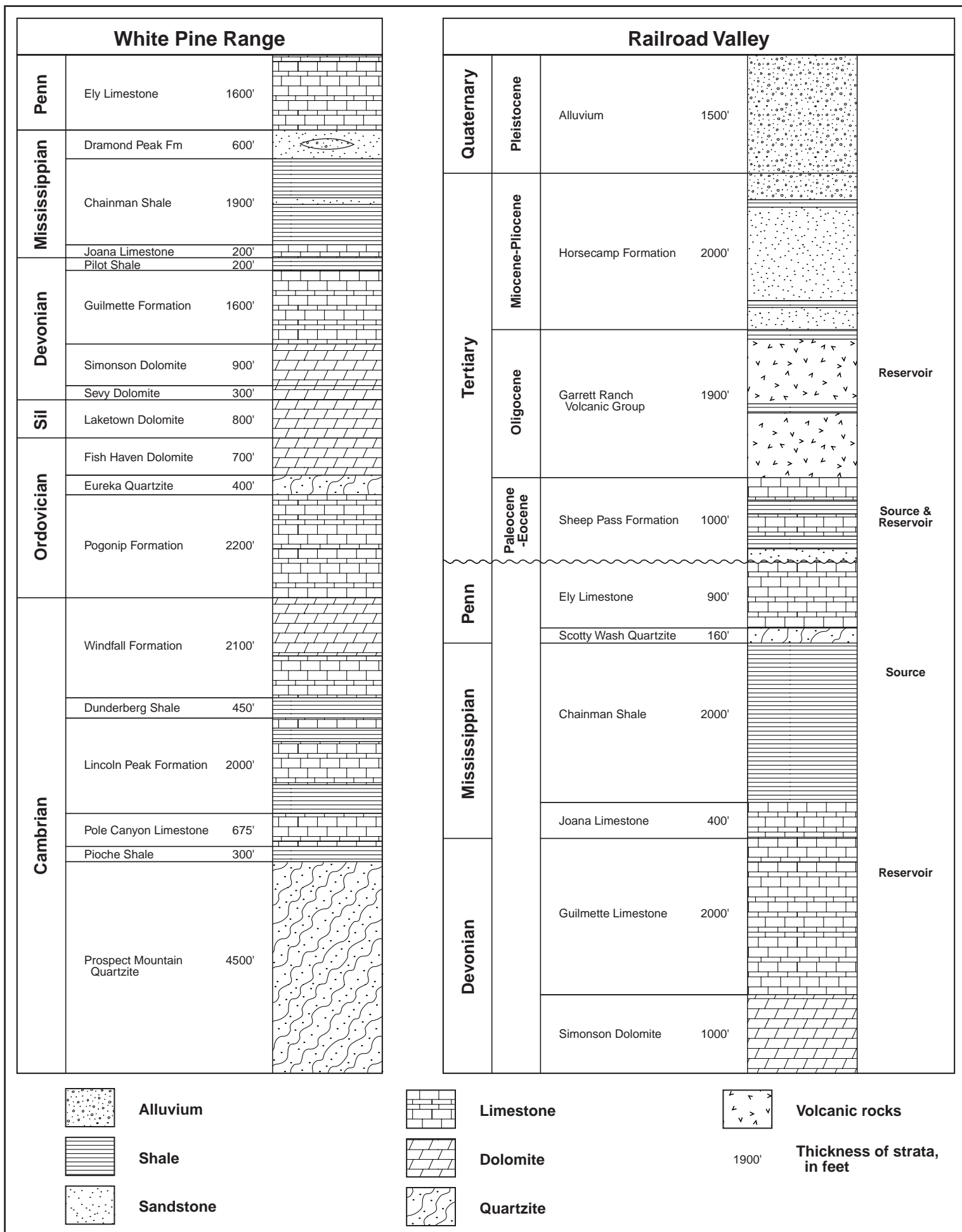


Figure 43. Stratigraphic columns for White Pine Range and Railroad Valley, eastern Nevada, indicating primary source and reservoir units. After [Montgomery \(1988b\)](#).

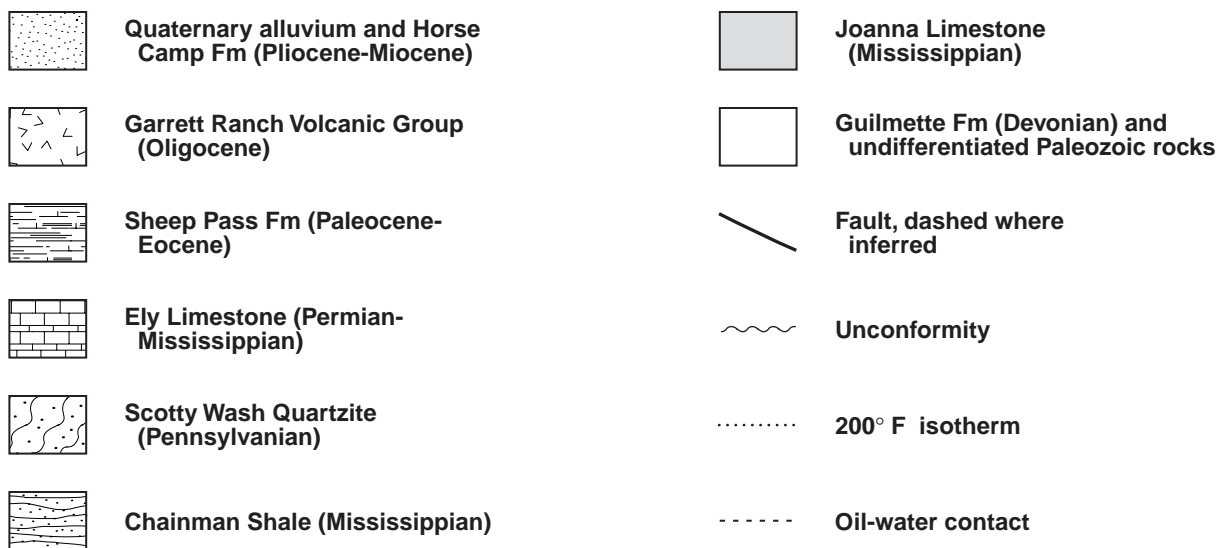
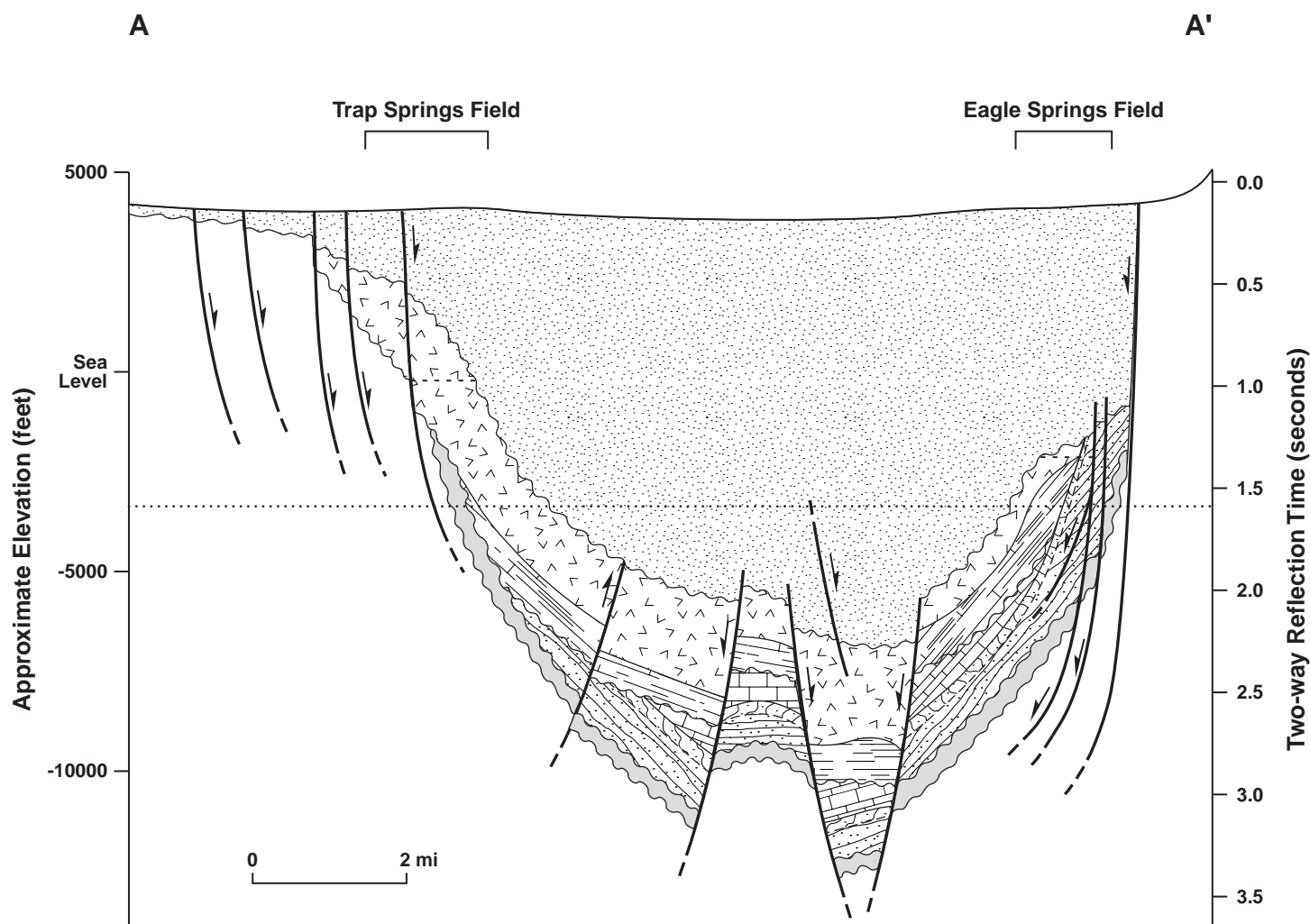


Figure 44. Cross section A-A' across Railroad Valley, Nevada (see [Figure 42](#) for location), showing trap types and possible location of basin-centered gas below 200° F isotherm. After [Poole and Claypool \(1984\)](#).

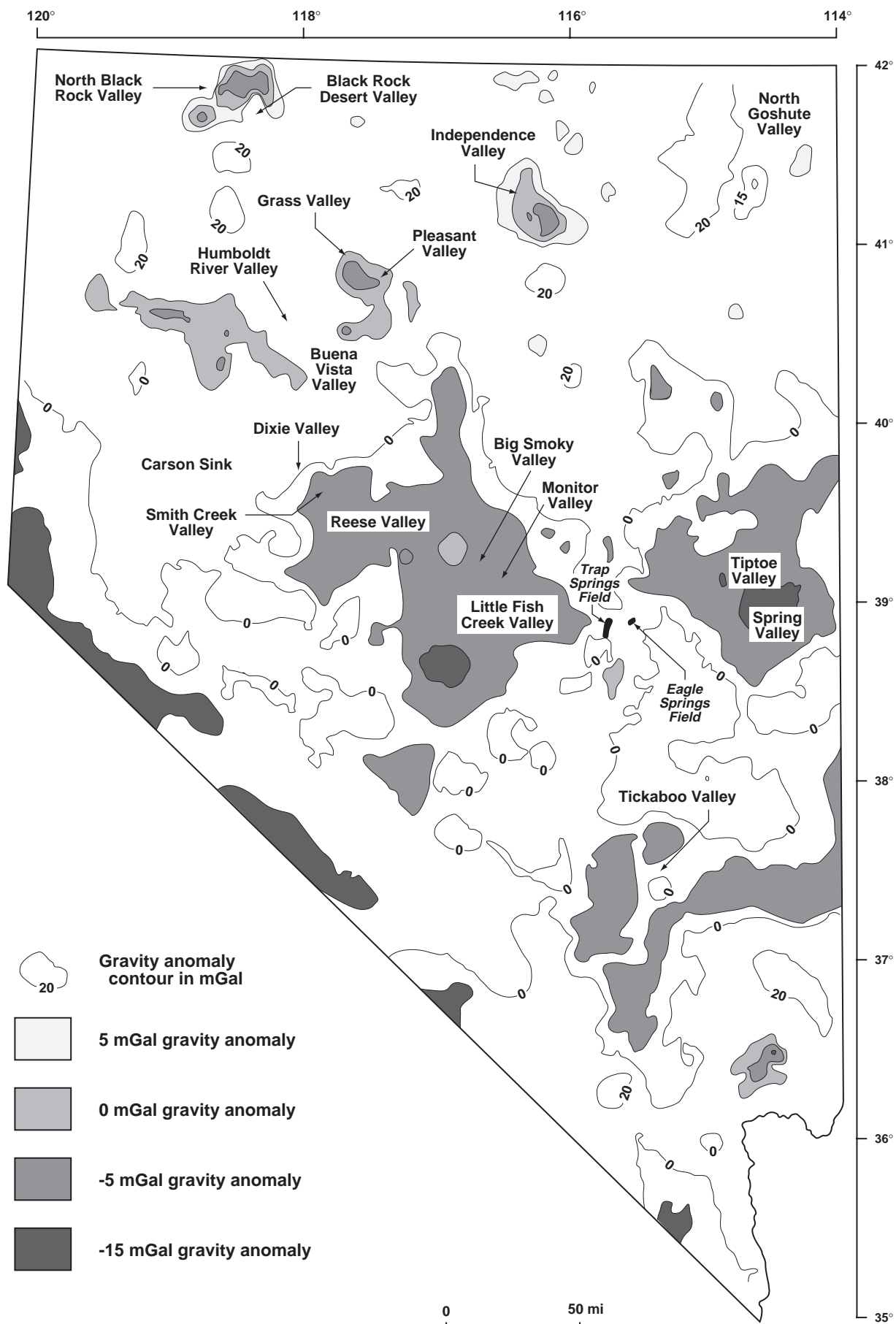


Figure 45. Gravity minima ("lows") indicating possible thick Tertiary valley fill where gravity low coincides with a graben/valley. After [Peterson \(1988\)](#).

GULF COAST–AUSTIN CHALK

GEOLOGIC SETTING

The Late Cretaceous Austin Chalk of the Gulf Coast was deposited in shallow water on the stable, gently dipping shelf of the Gulf Basin. The limits of deposition were from the present outcrop belt to the sharp break of the Cretaceous shelf edge (Figure 46). The Chalk overlies the shales of the Eagle Ford formation and is unconformably overlain by the Taylor Group (Figure 47). The dominant lithology is carbonate skeletal debris with some bands of clay, shale and organic-rich marl. The Chalk becomes increasingly shaley basinward and grades into the shales of the underlying Eagle Ford. Thickness increases downdip from less than 100 ft near the outcrop to over 650 ft at depths of 9,500 ft. Thickness also varies along strike reflecting variations in the shelf. In the Maverick Basin (Rio Grande Embayment), the Chalk exceeds 1,000 ft thickness, thins at comparable depth across the San Marcos Arch, and thickens again in the East Texas Basin.

Most structure observed in the Chalk reflects an extensional structural style related to opening of the Gulf Basin. Locally, structure may be complex, influenced by salt flow, anticlinal growth or drape related to differential compaction in underlying sediments.

HYDROCARBON PRODUCTION

The Austin Chalk has yielded oil and gas in both Texas and Louisiana for over 70 years. Development in Texas occurs in a 30 mile wide band that stretches from the Rio Grande in south Texas to the Louisiana state line.

Austin Chalk production in Louisiana had been limited to the central part of the state and was incidental to deeper exploration. The successful application of horizontal drilling at Brookeland field in Sabine County, east Texas, led to the first successful drilling for the Chalk in western Louisiana. At the same time, operators in existing fields of Avoyelles Parish began to apply horizontal drilling to exploit Austin Chalk reserves.

The Chalk in Louisiana generally produces from greater depths than in Texas. At Jack Moncrief and North Bayou fields, the Chalk produces high-GOR oil (oil ranging from 39° to 42.7° API gravity) from depths of about 14,500 ft. Farther west at Masters Creek field, the Chalk produces condensate and gas from 14,800 ft. These depths yield dry gas at Giddings. This change in hydrocarbon charge may be related to a southeast to northwest shift in geothermal gradient (Pollastro, U.S. Geological Survey, 1999, personal communication). Work on the geographic distribution of geothermal gradients in the Chalk remains incomplete, but will add substantially to understanding hydrocarbon generation beyond the models proposed in the Texas fairway.

The Chalk produces from natural fractures. Consequently, most of the production is associated with known fault zones or other structural features responsible for fracture development (Stapp, 1977). Locally, high fluid pore pressure may have contributed to fracturing (Corbett et al., 1987). Gas expansion is the principal driving mechanism in the reservoirs. Gas to oil ratios generally show an inverse relationship to structural position; that is, gas rich reservoirs tend to be structurally lower while oil rich reservoirs are shallower. This reflects increased generation of gas at greater depth (Figure 48). Reservoirs are directly related to the amount of fracturing; this prevents extensive migration and most hydrocarbons stay near the depths at which they were generated. Thin bentonite or shale beds limit vertical fracture growth. Different horizons are productive in different geographical areas. Upper benches of the Chalk are productive at Pearsall field in the western area; the lowermost Bench is the pay at the Giddings Area. Farther east at Brookeland field and in Louisiana, the clay/shale interbeds are absent and the Chalk may be fractured for its entire height. The source for Austin Chalk accumulations may be the underlying Eagle Ford shales or by carbonaceous beds within the Chalk itself (Stapp, 1977; Grabowski, 1981, 1984; Ewing, 1983; Hinds and Berg, 1990).

Fracture production is characterized by high initial rates of production as open fracture systems are drained. Production declines are very rapid and are followed by extended periods of low volume production, as microfractures and/or matrix permeability produce fluid to the open fractures penetrated by the wellbore.

EVIDENCE FOR BASIN-CENTERED GAS

The discovery of dry (non-associated) gas at the Giddings Deep field in Texas is of particular importance for exploration for other dry gas accumulations in the Austin Chalk. The Austin Chalk has generally been regarded as an oil play and certainly the drilling cycles of the 1970s and 1990s were driven by higher oil prices as well as technical advances. With an abundance of conventional and non-conventional gas plays in Texas, there has been little incentive for operators to drill the deeper, increasingly shaley Chalk in search of gas reserves, especially since the chalk was assumed to shale out at depths suitable for gas generation. Gas/oil ratios are relatively constant within most fields but at Giddings are known to increase about 10 fold across the field. Deep drilling was a deliberate effort to establish gas reserves. The deeper drilling also identified chalk lithology at greater depths than had previously been expected (Pollastro, U.S. Geological Survey, 1999, personal communication).

The Austin Chalk apparently can produce commercial gas at Giddings field in Texas. Local drilling at Giddings has extended the Chalk play downdip past its previously assumed limits. The extension of Chalk exploration into Louisiana has identified areas of gas and condensate production. Areas including east Texas, and western and southern Louisiana may be the best area for future gas development. Potential exists for westward extension of the play downdip of the oil producing trend. The presence of clean chalk beyond its currently assumed limits at the Cretaceous shelf edge will be a determining factor. Also necessary are fracturing mechanisms to produce reservoirs. The presence of source beds within the Chalk and the underlying Eagle Ford shale insure gas generation at sufficient depth and temperature. Salt flow, regional dip change, and faulting associated with flexure of the Cretaceous shelf edge could all contribute to fracture development.

- 1) The Austin Chalk and the underlying Eagle Ford shale are sufficiently mature for gas and gas-condensate generation throughout the known extent of the play. The Chalk appears to be gas-prone at shallower depths in the western portion of the play in Texas.
- 2) Clean, brittle chalk suitable for fracturing is present at depths of gas generation in east Texas and eastward into Louisiana. The downdip limits at which the chalk grades to shale in this area are not yet fully established.
- 3) Fractures within the Chalk constitute the reservoir; therefore, reservoirs become limited to areas of fracturing. In this respect the Austin Chalk differs from a typical continuous gas accumulation. Although gas may be present in the chalk matrix, fracture permeability is necessary for production. Thus, the extent of fracturing will restrict formation of gas-producing reservoirs. Salt flow, faulting, differential compaction, and other structural or stratigraphic events can create fracturing throughout the known extent of the play. Fracture trends may be identified regionally, but fracturing suitable for reservoir development will be limited locally.
- 4) Temperatures in the deep Chalk play reach 350 °F at Giddings field in Texas. The geothermal gradient apparently changes in Louisiana from northwest to southeast and appears to match the shift from gas-prone reservoirs to high-GOR oil reservoirs. The nature and extent of this change is not understood. A better understanding of this phenomenon might help identify gas-prone Austin Chalk in the eastern part of the play.
- 5) The only significant water production in the deep Chalk play is at Masters Creek field in Louisiana, where the Chalk is in fracture communication with the underlying geopressured Eagle Ford Formation.

KEY ACCUMULATION PARAMETERS

Identification

West Gulf Coast, Texas and Louisiana, Deep Austin Chalk (Cretaceous)

Geologic Characterization of Accumulation:

- a. Source/reservoir** Underlying Eagle Ford shale and self-sourced from interbedded organic material ([Grabowski, 1981, 1984](#); [Stapp, 1977](#)); intraformational fractures are the reservoir ([Stapp, 1977](#); [Corbett et al., 1987](#)).
- b. Total Organic Carbons (TOCs)** Eagle Ford = 1.5-8% ([Montgomery, 1990a; 1990b](#)); Austin Chalk = 0.3-2.5% ([Grabowski, 1981](#))
- c. Thermal maturity** Thermal alteration index ranges from 1 to 2 at 2000 ft to 3 at 9000 ft. Ratios of Extractable Organic Matter (EOM) to Total Organic Content (TOC) range from less than 10% in the immature zone to 45% in the oil generation zone. Ratios decrease with greater depth reflecting the expulsion of generated hydrocarbons ([Grabowski, 1981, 1984](#); [Ewing, 1983](#); [Hinds and Berg, 1990](#)). Temperature gradient changes from south-central Louisiana to the Louisiana - Texas state line suggest lower temperatures to east and higher temperatures to west ([Pollastro, 1999](#), U. S. Geological Survey, personal communication).
- d. Oil or gas prone** Oil and gas productive from south Texas to central Louisiana; non-associated gas produced in the deep Giddings area below 10,000 ft.
- e. Overall basin maturity** Gulf Coast Basin is mature regionally.
- f. Age and lithologies** Late Cretaceous, coccolith- and foraminifera-rich chalk with thin interbedded shales and bentonites.
- g. Rock extent/quality** Extends from Maverick Basin of south Texas to central Louisiana; rock quality varies locally from east to west, but chalk grades to shale basinward ([Stapp, 1977](#); [Montgomery 1995](#)).
- h. Potential reservoirs**
- i. Major traps/seals** Interbedded shale and bentonite beds terminate vertical fracture development; fracture development occurs in areas of extensional or halokinetic (salt flow) faulting, or structural drape over underlying sediments.
- j. Petroleum generation/migration models** Thermogenic generation related to depth of burial ([Ewing, 1983](#); [Hinds and Berg, 1990](#); [Grabowski, 1981, 1984](#)); limited migration due to fracture compartmentalization.
- k. Depth ranges** Oil and gas productive at depths of 6000 ft to 14,000; dry gas productive at 10,000 to 14,000+ ft at Giddings field.
- l. Pressure gradients**

**Production and Drilling
Characteristics:**

- | | |
|---------------------------------------|---|
| a. Important fields/reservoirs | Giddings, Giddings Deep, Pearsall, Masters Creek, Brookeland, Moncrief |
| b. Cumulative production | Giddings (all)--2.8 TCFG, 414,800,000 BO; Pearsall--92 BCFG, 142,000,000 BO; Masters Creek 17 BCFG, 4,630,000 BO; Moncrief 5.4 BCFG, 447,000 BO |

**Economic
Characteristics:**

- | | |
|---|--|
| a. Inert gas content | Up to 6.5% CO ₂ and unspecified amount of H ₂ S at Giddings Deep (Moritis, 1995). |
| b. Recovery | Highly variable recoveries typical of fractured reservoirs. |
| c. Pipeline infrastructure | Good to excellent for most of play; fair in west-central Louisiana. |
| d. Exploration maturity relative to other basins | |
| e. Sediment consolidation | Consolidation/porosity reduction occur with depth of burial. |
| f. Porosity/completion problems | High temperatures (350°) at Giddings Deep, require special mud systems and “hostile environment” downhole tools. Plugging of the fracture systems by drilling mud is a particular problem in Louisiana. Unlined laterals are more likely to collapse at the gas prone depths, (>10,000 ft) than in the shallower (6000-9000 ft) oil play. The underlying Eagle Ford shales are known to be geopressured in portions of Louisiana; fracture communication with the geopressured zones creates drilling hazards and increases water production. Greater weight of overburden may result in more rapid closure of fractures with withdrawal of fluid. |
| g. Permeability | |
| h. Porosity | |

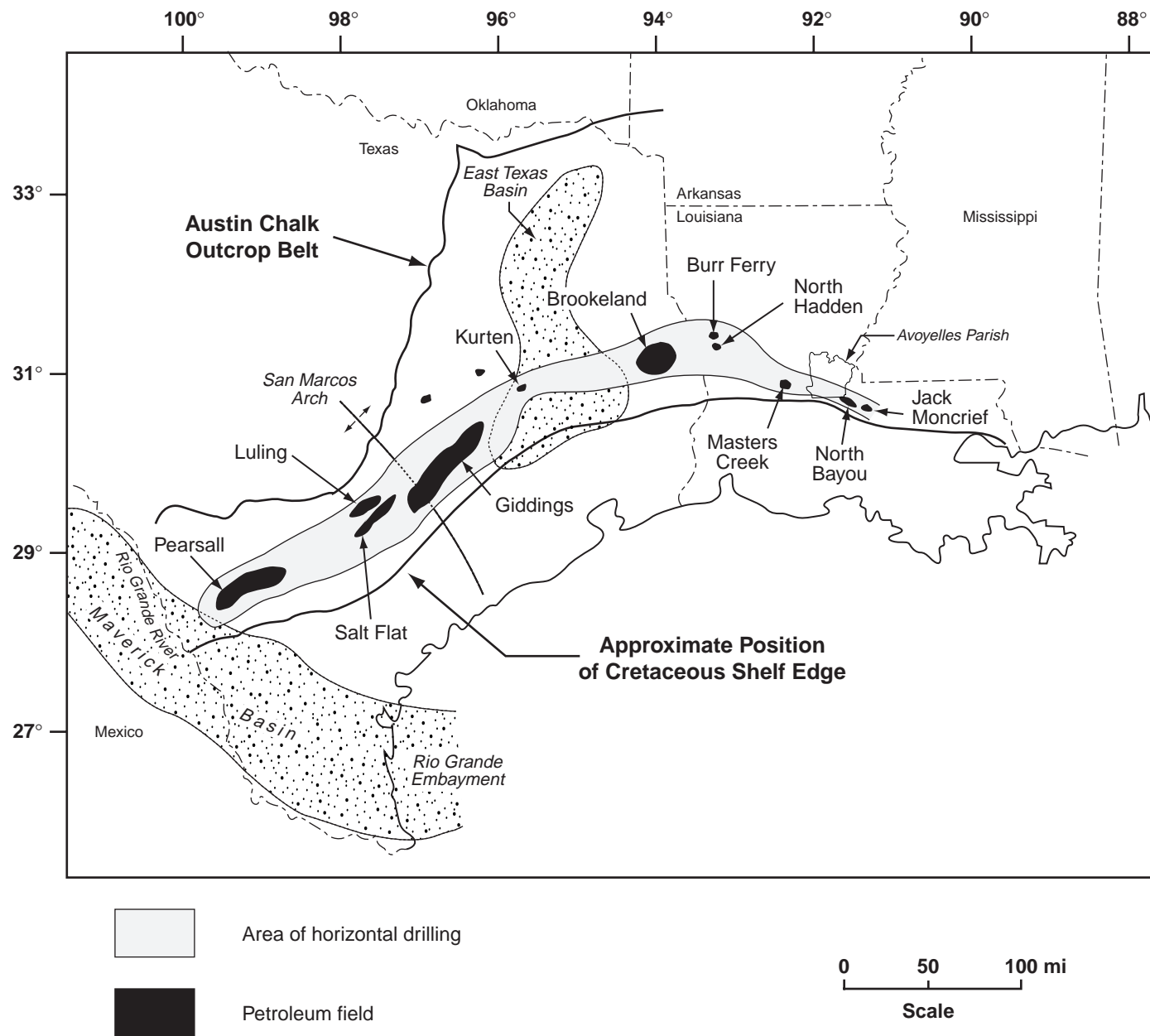


Figure 46. Regional map showing productive trend of horizontal drilling in the Austin Chalk, Texas and Louisiana. After [Montgomery \(1995\)](#).

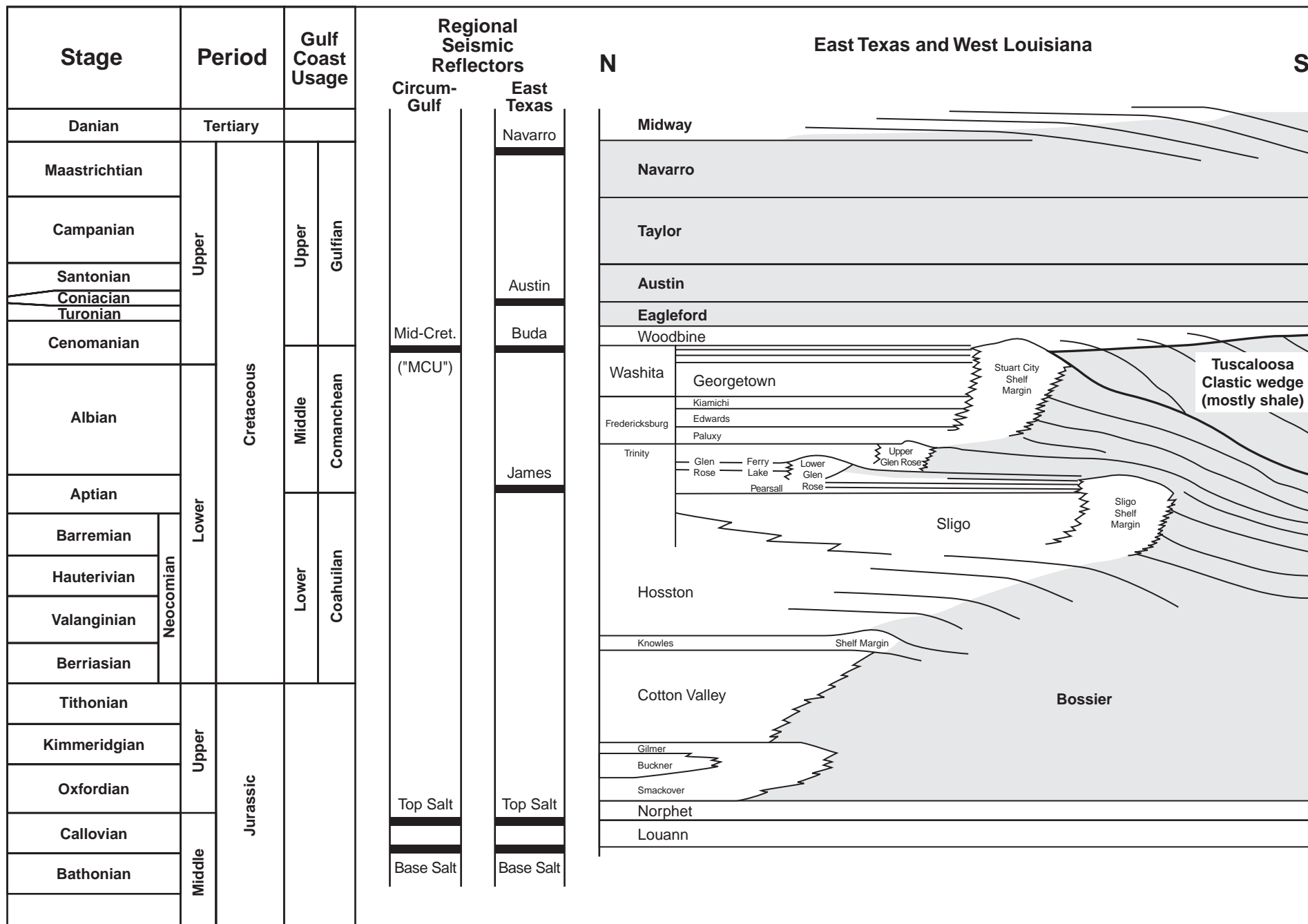


Figure 47. Stratigraphic column and cross section for East Texas and Western Louisiana. After [Winker and Buffler \(1988\)](#), and [Montgomery \(1995\)](#).

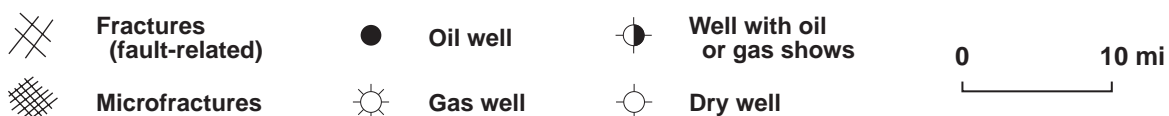
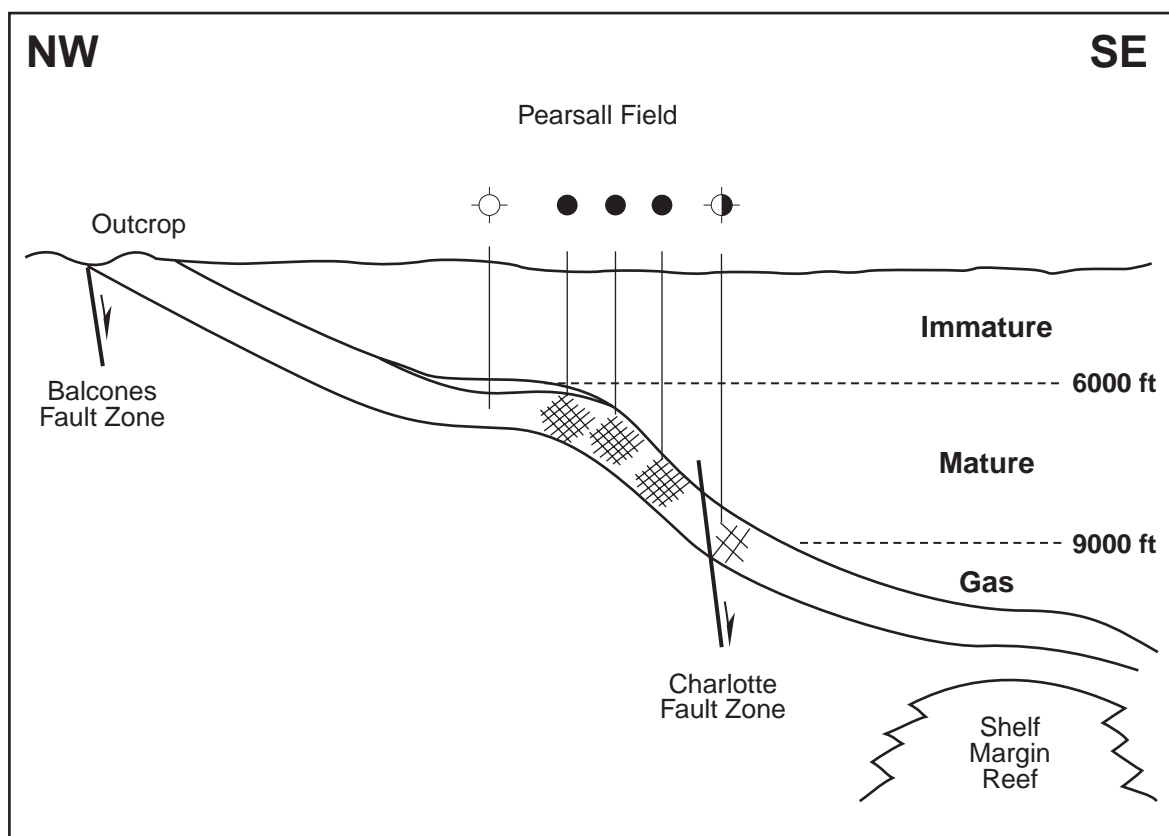
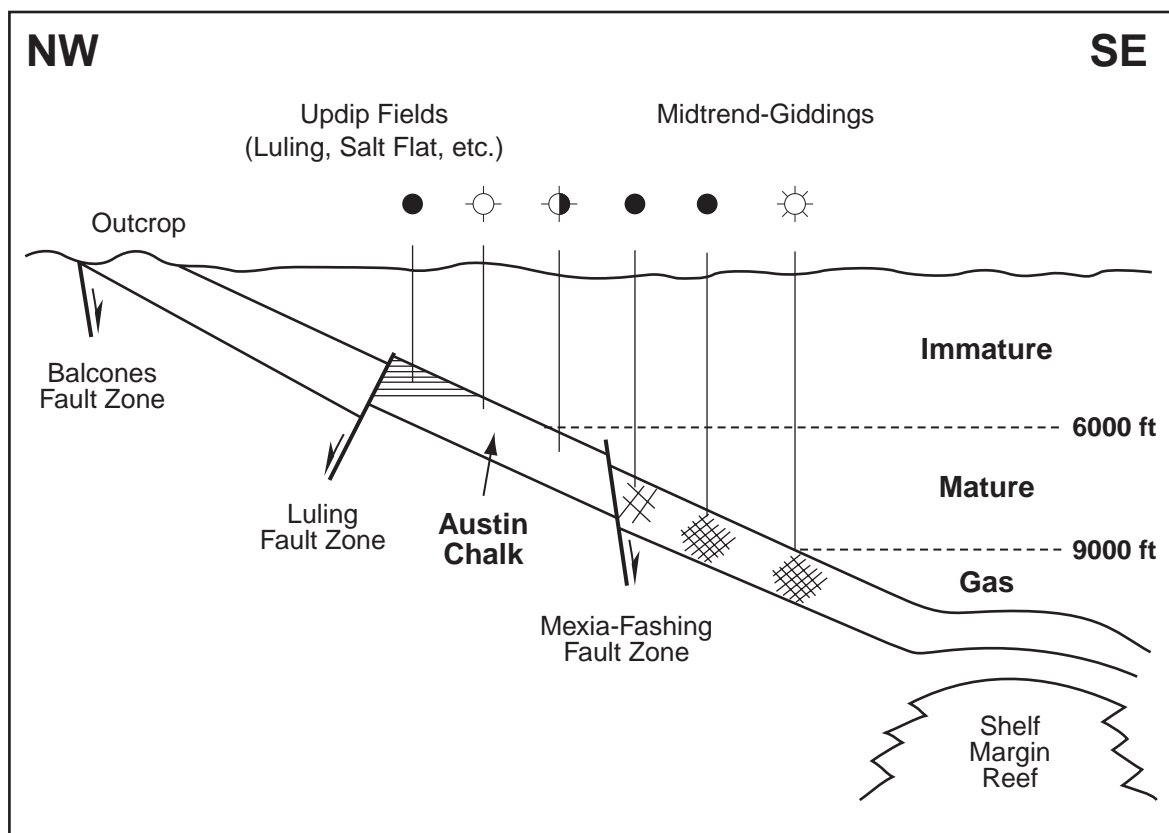


Figure 48. Generalized cross sections showing down-dip progression of hydrocarbon maturity levels and trap types in the Austin Chalk of southern Texas. After [Ewing \(1983\)](#) and [Montgomery \(1990b\)](#).

GULF COAST-EAGLE FORD FORMATION

GEOLOGIC SETTING

The Eagle Ford Formation was deposited during the late Cretaceous period on the gently sloping shelf of the Gulf Coast. [Figure 49](#) shows the location of the Eagle Ford gas generation area in south-central Texas and Louisiana. The formation unconformably overlies the Woodbine Group, which includes the Woodbine sands of east Texas and southwest Louisiana, the Tuscaloosa sands of central Louisiana, and the Buda limestone of Texas ([Figure 50](#)). Resting unconformably above the Eagle Ford is the Austin Chalk. The lower Eagle Ford is a transgressive unit composed of dark shales, while the upper unit is a highstand/regressive facies with thin limestones, shales, siltstones, and bentonites, and thin dolomites locally ([Dawson et al., 1993](#); [Stapp, 1977](#)). Regionally, the formation ranges in thickness from a feather edge in Arkansas to 100-150 ft across much of Texas and Louisiana. In response to underlying structure, the formation thickens to 300 to 400 ft in south Louisiana. Maximum thickness is about 800 ft in east Texas. Deposition occurred downdip from the current outcrop band to beyond the Cretaceous shelf margin. Dark shales in the upper Eagle Ford are absent in parts of east Texas, with the Austin Chalk overlying fine grained clastics mapped as Woodbine. [Montgomery \(1995\)](#) suggests this “missing” Eagle Ford may be due to changes in local terminology, but also states that the literature does not formally recognize this distinction.

Structure in the Eagle Ford generally reflects down to the basin extensional faulting, but locally, salt flow, anticlinal growth, or differential compaction in the underlying Woodbine/Tuscaloosa may also influence structure .

HYDROCARBON PRODUCTION

Production from the Eagle Ford is difficult to verify. [Stapp \(1977\)](#) noted completions of oil wells in the formation in Frio County, Texas (presumably in the Pearsall field area), but since these were in conjunction with Austin and/or Buda completions, there are no separate records of Eagle Ford production. Stapp further stated that the formation itself could not be considered a primary target because of its thinness and lack of permeability. More recently, [Dawson \(1997\)](#) found that low matrix permeabilities and low volumetric parameters of the formation preclude reservoir potential. The ductility of the shale interval hinders development of fractured reservoirs found in the more brittle overlying Austin Chalk and underlying Buda limestones, although carbonate and siliclastic beds in the upper interval may fracture.

Values of total organic content (TOC) in the Eagle Ford range from 1.0 to almost 10.0 % wt and thus suggest a high quality source rock. Formation samples yield total hydrocarbon generation potential (THGP) values from about 1 to over 50 mg HC/g rock. Plots of Hydrogen Index versus Oxygen Index suggest the Eagle Ford contains both type II and type III kerogens and is prone to both oil and gas generation ([Robison, 1997](#)). Maturation studies on Eagle Ford samples indicate onset of hydrocarbon generation at 7,500 ft original depth ([Noble et al., 1997](#)), matching the variation in maturity from deeper oil-prone Louisiana fields to shallower gas-prone fields in Texas. This generation depth corresponds to the results of maturation studies in the Austin Chalk ([Grabowski, 1984](#); [Ewing, 1983](#); [Hinds and Berg, 1990](#) ([Figure 51](#)).

EVIDENCE OF BASIN-CENTERED GAS

The lack of verifiable production history and reported lack of reservoir make the Eagle Ford a poor candidate for significant gas accumulations. The similarity to maturity in the Austin Chalk allows extrapolation from Austin or Tuscaloosa gas production to likely areas and depths of gas generation in the Eagle Ford. As a regionally extensive organic rich source rock, the Eagle Ford could generate gas over a large area downdip from the traditional Austin Chalk oil trend and in the vicinity of deep dry-gas and gas-condensate production in the Giddings area of Texas and southwest Louisiana. Production of such gas will require the development of fracture reservoirs in the Chalk or the underlying Buda formation. The Woodbine sands of eastern Texas grade basinward to shale; the Tuscaloosa sands of southern Louisiana probably grade likewise. The Tuscaloosa-Eagle Ford transition occurs at depths greater than 18,000 ft, a depth suitable for gas generation. The migration of such gas to conventional reservoirs would require faulting or fracturing ([Montgomery, 1995](#)). A widespread accumulation of gas in tight, silty Tuscaloosa sands in the transition zone is possible but speculative. Any such accumulation would be within the area of geopressuring in the Tuscaloosa, which would create drilling and completion problems.

KEY ACCUMULATION PARAMETERS

Identification

West Gulf Coast, Texas and Louisiana, Eagle Ford Shale (Cretaceous)

Geologic Characterization of Accumulation:

- a. Source/reservoir** Eagle Ford shale is self-sourced ([Noble et al., 1997](#); [Robison, 1997](#); [Stapp, 1977](#)); reservoir not developed ([Stapp, 1977](#); [Dawson, 1997](#)).
- b. Total Organic Carbons (TOCs)** Eagle Ford = 1.0 to almost 10% ([Robison, 1997](#)).
- c. Thermal maturity**
- d. Oil or gas prone** Either oil or gas prone based on kerogen types ([Robison, 1997](#)).
- e. Overall basin maturity** Gulf Coast Basin normally mature regionally.
- f. Age and lithologies** Late Cretaceous, lower section dominated by dark shales, upper section includes thin limestones, dolomites and bentonites in addition to shale ([Stapp, 1977](#); [Dawson, 1997](#)).
- g. Rock extent/quality** Regionally extensive shale (see [Figure 50](#)); poor reservoir quality.
- h. Potential reservoirs**
- i. Major traps/seals**
- j. Petroleum generation/migration models** Thermogenic generation related to depth of burial ([Ewing, 1983](#); [Hinds and Berg, 1990](#); [Grabowski, 1981, 1984](#); [Noble et al., 1997](#)); migration by faults and fractures to Austin Chalk and Buda Limestone, lateral migration to Woodbine sands ([Stapp, 1977](#); [Ewing, 1983](#); [Wescott and Hood, 1993](#)).
- k. Depth ranges** Oil and gas generative at current depths of 6000 ft to 14,000 ft.
- l. Pressure gradients**

**Production and Drilling
Characteristics:**

Not applicable

- a. Important
fields/reservoirs**
- b. Cumulative production**

**Economic
Characteristics:**

Not applicable; source rock only.

- a. Inert gas content**
- b. Recovery**
- c. Pipeline infrastructure**
- d. Exploration maturity
relative to other basins**
- e. Sediment consolidation**
- f. Porosity/completion
problems**
- g. Permeability**
- h. Porosity**

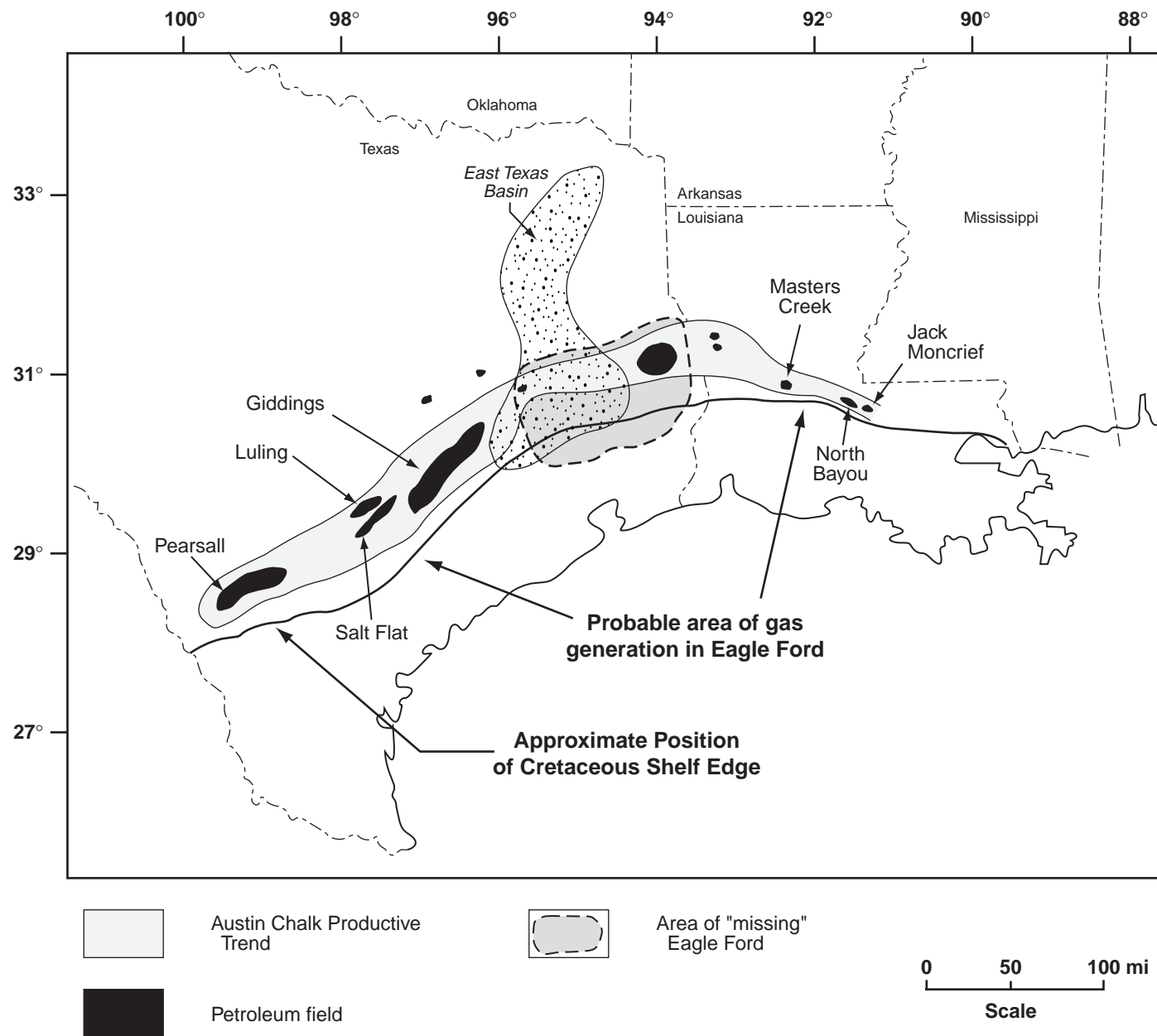


Figure 49. Regional map showing gas generation from Eagle Ford Formation, Texas and Louisiana. After [Montgomery \(1990b\)](#).

System	Series	Stage	Central Texas			East Texas Basin	Southeast Texas SW Louisiana		South Louisiana and Offshore		
Cretaceous	Upper	Maastrichtian	Escondido	Navarro		Navarro	Navarro	Navarro	Navarro		
			Olmos								
		Campanian	San Miguel	Taylor	alkaline volcanics	Taylor	Taylor	Taylor	Selma		
			Anacacho								
			Upson								
		Santonian	Austin Chalk			Austin Chalk	Austin Chalk	Austin Chalk	Austin Chalk	Brownstown	
		Coniacian								Ector	
		Turonian	Eagle Ford			Eagle Ford	Eagle Ford	Eagle Ford	Eagle Ford		
		Cenomanian	Woodbine	Buda			Woodbine	Woodbine	Buda	Tuscaloosa	
							Buda			Buda	
			Washita	Del Rio		Del Rio - Grayson	Washita	Grayson	Washita	Grayson	



Austin Chalk interval



Eagle Ford Formation

Figure 50. Stratigraphic column and correlation in the Upper Cretaceous interval, U. S. Gulf Coast. After [Salvador and Muneton \(1989\)](#).

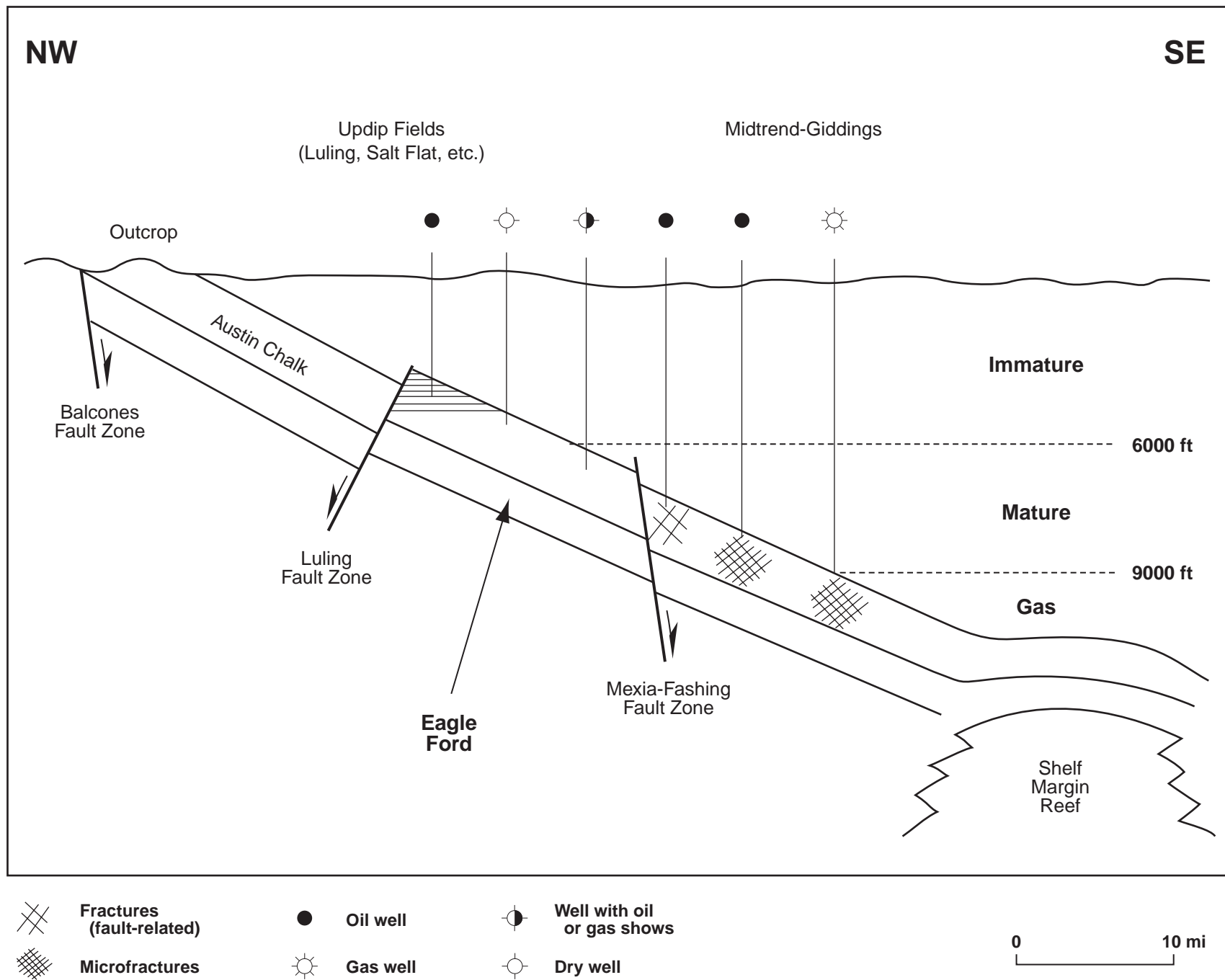


Figure 51. Generalized cross section showing down-dip progression of hydrocarbon maturity levels and trap types in the Eagle Ford Formation of southern Texas. After [Ewing \(1983\)](#) and [Montgomery \(1990b\)](#).

GULF COAST-TRAVIS PEAK/COTTON VALLEY FORMATIONS

GEOLOGIC SETTING

The Lower Cretaceous Travis Peak Formation and Upper Jurassic Cotton Valley Group contain FERC-designated tight gas sands that were widely deposited across eastern Texas, northern Louisiana and into the Mississippi salt basin (Figure 52). The lower part of the Cotton Valley also contains both reef-forming carbonates and oolitic shoals. Sandstone distribution in the Cotton Valley generally is more consistent than that in the Travis Peak.

In east Texas, Travis Peak deposition occurred in a fluvial-deltaic environment that prograded from the northwest (Bushaw, 1968; Saucier, 1985; and Tye, 1989). Underlying Cotton Valley sands may be barrier-island type deposits. Interpretations of stratigraphic sequence have defined a number of depositional sub-environments (Figure 53) in east Texas and western Louisiana that consist of:

1. a braided to meandering fluvial system;
2. interbedded deltaic/fluvial deposits—fluvial deposits distally become encased in deltaic rocks;
3. paralic deposits that interfinger with the above two systems near the top of the Travis Peak; and
4. shelf deposits near the downdip edge of the Travis Peak; these sediments interfinger with and onlap deltaic and paralic deposits (Dutton et al., 1993).

Thickness of the Travis Peak Formation ranges from 500 to 2,500 ft, and generally increases to the southeast (Figure 53). The upper 200 ft of the formation holds the most potential for basin-centered gas development. Most productive intervals occur at depths of 3,100 to 10,900 ft. Cotton Valley low permeability sands range in thickness from 1,000 to 1,400 ft thick and occur at depths of 5,000 to 11,000 ft; Schenk and Viger (1996) suggest that Cotton Valley reservoirs may extend to depths as much as 20,000 ft. Reservoir continuity is often interrupted by small-scale sedimentary disturbances that include bedforms, biogenic features, clay drapes, and scour surfaces (Gas Research Institute, 1991).

Since 1980, activity targeting the Cotton Valley involves a pinnacle reef play which is developing along the western shelf of the East Texas basin (Montgomery, 1996) and may extend into the Sabine platform trend into Louisiana (Figure 52). Reef development appears to coincide with localized salt-tectonic positive features that provided a shoaling environment. These carbonate buildups were 200 to 400 ft thicker than the surrounding interreef sediments and had an areal extent of 200 to 800 acres (Montgomery, 1996).

Growth faulting throughout the area of the Cotton Valley and Travis Peak trends may play an important part in the upward migration of hydrocarbons. Jurassic rocks contain the greatest number of faults, probably related to salt tectonism (Montgomery, 1996). Salt structure formation provided shoaling environments for deposition of oolites and other high energy sediments. From the Jurassic to the Tertiary, salt tectonism generated local fracturing that enhanced reservoir permeability (Coleman and Coleman, 1981; Saucier, 1984).

The East Texas and North Louisiana salt basins may have formed by graben development that resulted from continental rifting and the opening of the Gulf of Mexico basin (Figure 52). These grabens are bounded by down-to-the-basin faults, which include the Mexia-Talco and the South Arkansas fault zones (Kehle, 1971; Wood and Walper, 1974; and Finley, 1986). Other dominant structural features in the play area include the Sabine uplift and the Monroe uplift in northeastern Louisiana. Development of the Sabine uplift is speculative; however, evidence points to a compressional origin (Jackson and Laubach, 1988).

HYDROCARBON PRODUCTION

As of 1993, 860 wells were completed within the Travis Peak Formation. Cumulative production from 1970 to 1988 amounted to 508-plus BCFG, with an estimated ultimate recovery of 1,269 BCFG. Average recoveries per well varied from 1.8 BCFG in east Texas to 1.4 BCFG in north Louisiana. Initial production rates increased from 0 to 765 MCFGPD prior to stimulation to 500 to 1500 MCFGPD after fracturing. Production rates declined up to 65% in the first 1 to 2 years. [Dutton et al. \(1993a, 1993b\)](#) estimated the resource base to be 6.4 TCFG.

Cotton Valley wells totaled 2,870 "tight completions" as of 1993. Cumulative production was 2,665.5 BCFG, with an estimated ultimate recovery of 4,999 BCFG. Average well recoveries varied from 1.8 BCFG in east Texas to 2.4 BCFG in north Louisiana. Production rates increased from 50 MCFGPD prior to stimulation to 500 to 1,500 MCFGPD after fracturing. Decline rates were somewhat less than those of the Travis Peak, with an estimated 46% decline in the first 1 to 2 years of production. The rate of water production decreased to a 50 barrel per day average in the same time period. The presence of a gas/water contact in any part of the play remains unknown. R. M. Cluff (The Discovery Group, 1999, personal communication) believes multiple gas/water contacts exist. [Dutton et al. \(1993a, 1993b\)](#) estimated the resource base for Cotton Valley tight reservoirs to be 24.2 TCFG.

The early stages of development of the Cotton Valley play included easily identifiable "blanket"-type sands originating from well-developed strands, barrier islands, and tidal bars. [Finley \(1986\)](#) suggested a newer, tight-gas sandstone play located generally downdip from the more permeable sands noted above. Distal to proximal delta-front deposits dominate this hypothetical play, which may extend from northwestern Louisiana into the eastern and central parts of the East Texas basin.

EVIDENCE FOR BASIN-CENTERED GAS

Widespread production, gas shows, and the occurrence of overpressuring and underpressuring indicate a potential for basin-centered gas accumulations. Most Travis Peak and Cotton Valley fields are overpressured, but some data indicates underpressuring in the Cotton Valley interval of the Oak Hill field, and in the Travis Peak lower zone of the Waskom field; the Cotton Valley limestone at Teague field reaches a pressure gradient of 0.66 psi per ft ([Kosters et al., 1989](#)). Pressure gradients are highest in the underlying Cotton Valley carbonates. Pressure gradients appear slightly higher in Cotton Valley sandstone reservoirs than in Travis Peak sandstone reservoirs. This may result from their proximity to source rocks, with some leakage from the Travis Peak. Pressure communication between the Travis Peak and Cotton Valley reservoirs may exist in east Texas.

In-situ generation of hydrocarbons does not appear likely for Travis Peak reservoirs. Thermal maturity data indicates that Travis Peak strata are well within the "oil window" (Ro values range from 1.0 to 1.8%); however, TOC values for interbedded Travis Peak shales generally are less than 0.5% ([Dutton et al., 1993a, 1993b](#)).

Cotton Valley strata have a higher likelihood for in-situ hydrocarbon generation. Beneath the Cotton Valley sands is the Bossier shale ([Figure 54](#)). [Montgomery \(1996\)](#) calls the Bossier "a dark, somewhat organic-rich interval," and local thickness changes of 400 feet occur on the western shelf of the East Texas basin ([Forgotson and Forgotson, 1976](#); [Montgomery, 1996](#)). The Bossier may have generated and expelled hydrocarbons in Late Cretaceous time ([Wescott and Hood, 1991](#); and [Montgomery, 1996](#)). [Schenk and Viger \(1996\)](#) believe some hydrocarbons in this play may have originated in mudstones in the lower part of the underlying Jurassic Smackover Formation ([Figure 54](#)).

KEY ACCUMULATION PARAMETERS

Identification

East Texas Basin and Mississippi-Louisiana Salt Basins Province; Travis Peak-Cotton Valley tight sands basin-centered gas accumulation

Geologic Characterization of Accumulation:

- | | |
|---|---|
| a. Source/reservoir | Source rocks include: Bossier shale (Upper Jurassic Cotton Valley group), and mudstones and carbonates of the Upper Jurassic Smackover Formation. Reservoir rocks include: Sandstones and carbonates of the Upper Jurassic Cotton Valley group and Lower Cretaceous Travis Peak Formation. |
| b. Total Organic Carbons (TOCs) | Values for the interbedded Travis Peak shales are less than 0.5%; content of the underlying Jurassic Bossier Shale and Smackover shales and carbonates is unavailable. |
| c. Thermal maturity | R _o 1.0 – 1.8% (values from Travis Peak interbedded shales). Possibly overmature in deepest rocks. |
| d. Oil or gas prone | Both oil and gas prone; however, source rocks referred to are specifically noted by Wescott and Hood (1991) to have generated oil. |
| e. Overall basin maturity | Maturation levels are moderate. |
| f. Age and lithologies | Upper Jurassic to Lower Cretaceous sandstones. |
| g. Rock extent/quality | Apparent basin-wide source and reservoir rock distribution; rocks are highly variable in reservoir quality because of quartz overgrowths and calcite cement, and minor amounts of clay and dolomite. |
| h. Potential reservoirs | Many producing reservoirs. |
| i. Major traps/seals | Carbonates and evaporites of the overlying Sligo and Pettet formations and mudstones within the Travis Peak. |
| j. Petroleum generation/migration models | Little chance of in-situ generation within the Travis Peak; however, Cotton Valley reservoirs may be self-sourced as in Weimer's (1996) Denver basin "cooking pot" model. Migration of gases along fracture and fault systems from the Upper Jurassic into Travis Peak reservoirs probably occurred, but may not be necessary if the Bossier shale generated sufficient hydrocarbons to charge both the Cotton Valley sands and Travis Peak sands, provided the two units are in pressure communication with one another. |
| k. Depth ranges | Travis Peak reservoirs range from 3100 to 10,900 ft; potential reservoir depths may exceed 15,000 ft. Cotton Valley reservoirs range from 5,000 to 11,000 ft and may go as deep as 20,000 ft. |
| l. Pressure gradients | Travis Peak - 0.38 to 0.52 psi/foot; Cotton Valley sands - 0.32 to 0.55 psi/ft; Cotton Valley carbonate (oolitic shoal reservoirs) - 0.50 to 0.66 psi/ft. |

Production and Drilling Characteristics:

- | | |
|---------------------------------------|---|
| a. Important fields/reservoirs | Bethany (Travis Peak), Carthage (Travis Peak, Cotton Valley), Waskom (Travis Peak, Cotton Valley), Trawick (Travis Peak), Opelinka (Travis Peak, Rosewood (Cotton Valley), Henderson North (Travis Peak, Cotton Valley), Blocker (Cotton Valley). |
| b. Cumulative production | Travis Peak - 508.3 BCFG (1970-1988); Cotton Valley - 2,665.5 BCFG (1970-1988). |

Economic Characteristics:

- | | |
|---|---|
| a. Inert gas content | |
| b. Recovery | Recoveries vary depending on permeability (degree of cementation and fracturing), and porosity. |
| c. Pipeline infrastructure | very good. |
| d. Exploration maturity relative to other basins | |
| e. Sediment consolidation | Most rocks are well indurated. |
| f. Porosity/completion problems | Iron oxide precipitates common in some Cotton Valley sandstone reservoirs, calcite and silica cementation restrict porosity, minor clay problems. |
| g. Permeability | Travis Peak - 0.0004 to 0.8 md; Cotton Valley - 0.015 to 0.043 md. |
| h. Porosity | Travis Peak - 5-17%; Cotton Valley - 6 to 11%. |

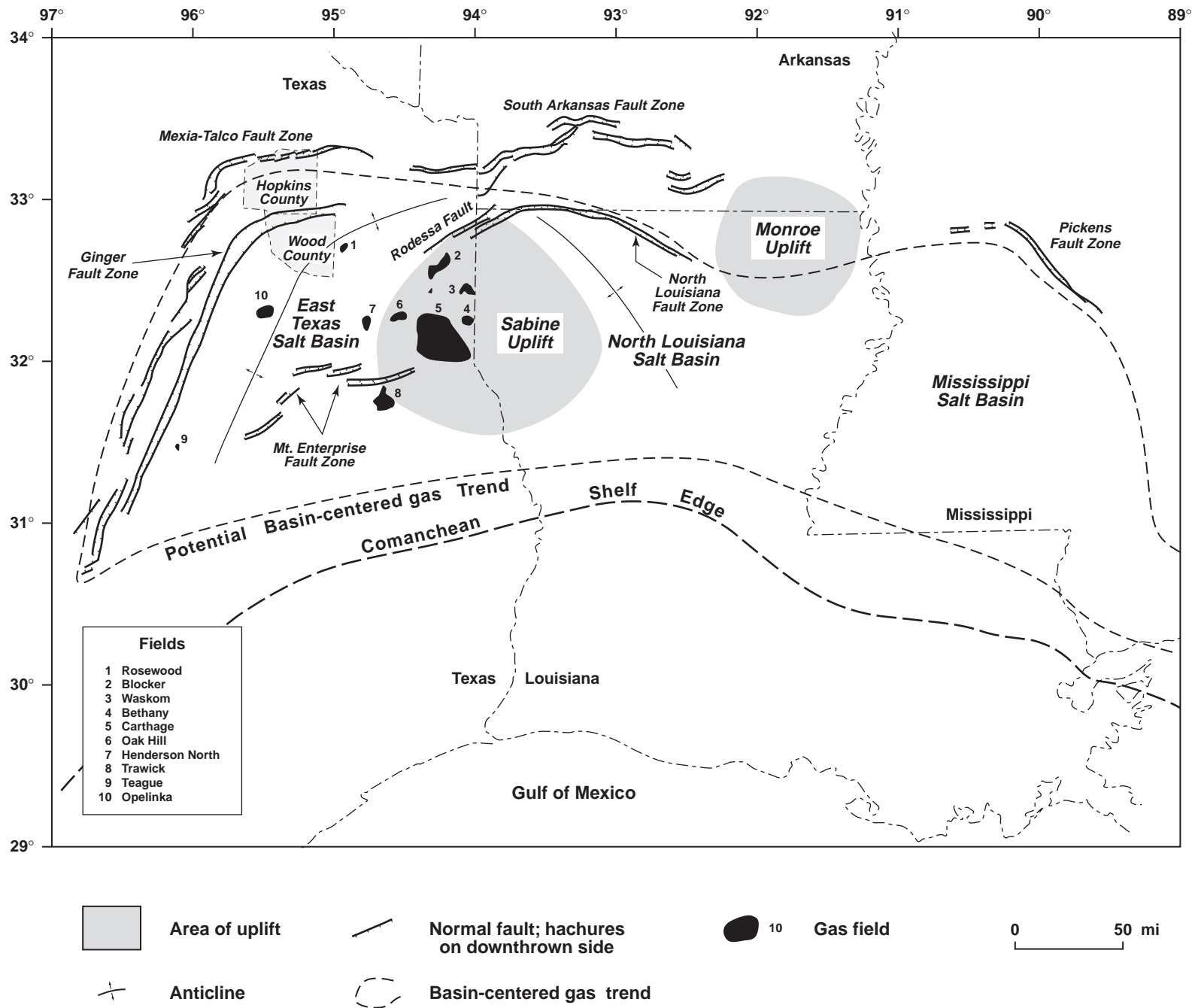


Figure 52. Regional tectonic map of the central Gulf coastal region showing potential basin-centered gas trend, gas fields in Travis Peak and Cotton Valley formations, and location of Hopkins and Wood counties (for cross-section A-A' illustrated in Figure 53). After Dutton et al. (1993a, 1993b).

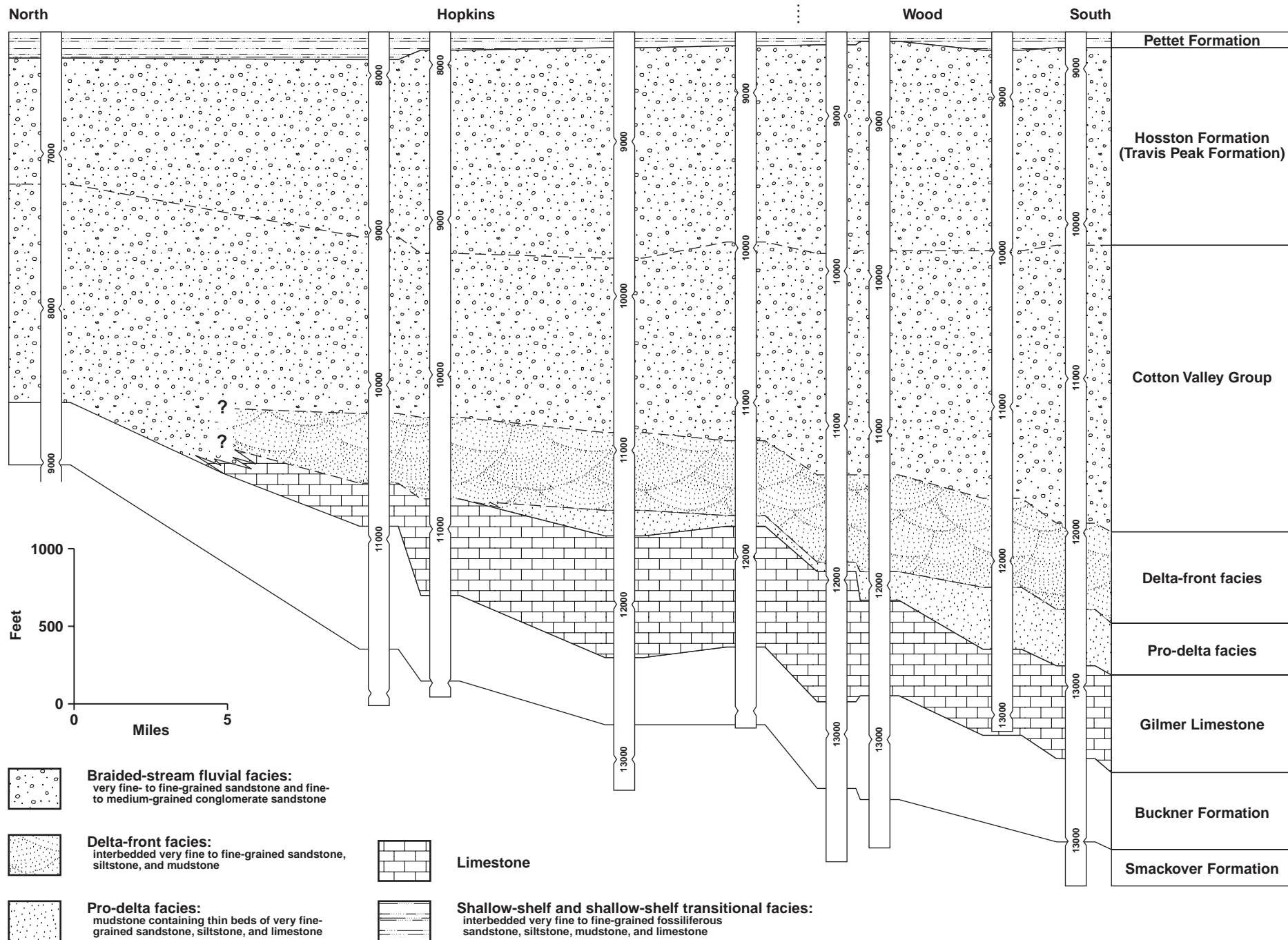


Figure 53. North-south dip-oriented cross section showing Travis Peak and Cotton Valley sandstone facies in East Texas Basin, Hopkins and Wood Counties, Texas. **Figure 52** shows the location of both counties. Well depths are in feet below mean sea level. After [Kosters et al. \(1989\)](#).

System	Series	Group	Formation
Cretaceous	Coahuilan	Nuevo Leon	Sligo/Pettet
			Travis Peak/Hosston
Jurassic	Upper	Cotton Valley	Cotton Valley Sandstone (Upper Cotton Valley/Schuler)
			Bossier Shale
			Cotton Valley Limestone (Gilmer/Haynesville)
		Louark	Buckner
			Smackover

Figure 54. Stratigraphic column of parts of the Jurassic and Cretaceous systems in east Texas and northern Louisiana. After [Finley \(1986\)](#).

HANNA BASIN

GEOLOGIC SETTING

The Hanna Basin is an intermontane basin in the Rocky Mountain foreland province in southeast Wyoming (Figure 55). The basin covers about 1,000 square miles and contains almost 38,000 ft of Cretaceous and Tertiary sediments (Figure 56). At least 18,000 ft of Late Cretaceous and early Tertiary sediments were deposited within 15 million years, creating thermally mature hydrocarbon source rocks in the basin center (Bierei and Surdham, 1986; Bierei, 1987). The Upper Cretaceous Medicine Bow, Lewis and Mesaverde Formations consist of up to 15,000 ft of dark marine organic-rich shales (Figure 57). The Eocene-Paleocene Hanna and Ferris Formations include almost 14,000 ft of organically rich lacustrine shales, coals and fluvatile sandstones (Perry, 1992; Bierei, 1987; Matson, 1984a, b). This excessive sedimentation resulted from abrupt basin subsidence associated with Laramide tectonism (Lillegraven, 1995; Bierei and Surdham, 1986; Shelton, 1968). The basin is asymmetric and is surrounded by numerous Laramide thrust faults (Figures 55 and 56).

The high subsidence rates that occurred in the Hanna basin are typical of wrench basins with strike-slip faulting (Perry, 1992).

HYDROCARBON PRODUCTION

The Hanna basin has several fields that produce both oil and gas (Kaplan and Skeen, 1985; Matson, 1984a, b; Porter, 1979b; McCaslin, 1978). To date, natural gas has been found only in sandstone reservoirs (Mitchell, 1968). The nonmarine rocks are currently being explored for coal and coal gas (Perry, 1992). There is no current production of coal gas in the basin.

EVIDENCE FOR BASIN-CENTERED GAS

Sparse exploratory drilling and lack of data make forecasts difficult. The Hanna basin has similar rock sequences to the Greater Green River basin, where Law and others (1984; 1989) have described basin-center gas systems. Pontolillo and Stanton (1994) measured vitrinite reflectance values greater than 1% below 11,000 ft in the Champlin and Brinkerhoff wells; these values exceed the 0.8% threshold that generally indicates the top of abnormal pressures and possible thermogenic gas generation (Johnson and Finn, 1998; Law, 1984) (Figure 58).

Late Cretaceous marine rocks in the basin show total organic carbon (TOC) values greater than 0.5%. The Hanna, Ferris, Medicine Bow, and Mesaverde Formations have coal beds and carbonaceous shales with variable TOC values (0.5 to 35.6 wt% avg, 3.2 wt% TOC). Marine sediments of the Lewis, Steele, Niobrara, and Frontier Formations have TOC range of 0.4 to 4.3 and average of 1.5 wt% TOC (Bierei, 1987).

Most of the known traps are structural closures around the edges of the basin (Matson, 1984a, b). Several structural/stratigraphic traps are also present (Porter, 1979a; McCaslin, 1978). Stratigraphic traps may occur in the deeper part of the basin, in low permeability and possibly overpressured Eocene, Paleocene and Upper Cretaceous rocks (Matson, 1984a, b). Major seals include the black/dark shales of the Cretaceous Mowry, Steele, Thermopolis, and Mesaverde Formations, and Paleocene and Eocene rocks.

Time-temperature calculations locate the oil generation window at 7,200 to 11,480 ft depth in the basin center. Apparently, hydrocarbon generation began about 80 Ma at the base of the Late Cretaceous section in the Hanna basin. Transformation models show that source rocks generated and expelled hydrocarbons very quickly. At present, the Hanna basin is not generating any significant amounts of hydrocarbons.

KEY ACCUMULATION PARAMETERS

Identification	Rocky Mountain Foreland Province; Upper Cretaceous and Paleocene Ferris and Hanna Formations
Geologic Characterization of Accumulation:	
a. Source/reservoir	At least 5.5 km (18,000 ft) of Late Cretaceous and early Tertiary sediments were deposited within 15 m.y., creating thermally mature hydrocarbon source rocks in the basin center (Bierei and Surdham, 1986; Bierei, 1987). The Upper Cretaceous Medicine Bow, Lewis and Mesaverde formations consist of up to 4572 m (15,000 ft) of marine dark, organic rich shales. The Eocene-Paleocene Hanna and Ferris formations consist of up to 4270 m (14,000 ft) of organically rich lacustrine shales, coals and fluvial sandstones (Perry, 1992; Bierei, 1987; Matson, 1984a, b).
b. Total Organic Carbons (TOCs)	Moderately good to good late Cretaceous marine source rocks with TOCs greater than 0.5%. The Hanna, Ferris, Medicine Bow, and Mesaverde formations have coal beds and carbonaceous shales with variable TOC values (0.5 to 35.6 wt% avg, 3.2 wt% TOC). Marine sediments of the Lewis, Steele, Niobrara, and Frontier formations have TOC range of 0.4 to 4.3 and average of 1.5 wt% TOC (Bierei, 1987).
c. Thermal maturity	In the Champlin and Brinkerhoff wells $R_o > 1\%$ below 11,000 ft; greater than 0.8% generally indicates the top of abnormal pressures (Johnson and Finn, 1998; Law, 1984). In #1 Hanna well (Figure 55), $R_o < 0.7\%$ to 10,000 ft; below 10,000 ft, R_o increases to 1.23% near bottom of hole, suggesting thermogenic gas generation and possible abnormal pressures below 10,000 ft (Perry, 1992; Spencer, 1987). R_o for Hanna and Ferris coals ranges from 0.45% to 0.6% (Pontolillo and Stanton, 1994). Pyrolysis profiles, combined with kerogen elemental analysis, also suggest generation of gas and possible overpressuring in low permeability rocks within the deeper part of the basin (Bierei, 1987). Temperature-depth plots, time-temperature profiles, and the bottom hole temperature in the Forgeston, Amoco, and Humble wells ranging from 204 to 240° F all suggest that overpressuring is present (Johnson and Finn, 1998; Spencer, 1987).
d. Oil or gas prone	Prone to both oil and gas. Several fields produce both oil and gas (Kaplan and Skeen, 1985; Matson, 1984a, b; Porter, 1979b; McCaslin, 1978). Natural gas has been found only in sandstone reservoirs (Mitchell, 1968).
e. Overall basin maturity	Kinky vitrinite reflectance present in the basin: interpreted as evidence of abnormal pressures in low permeability gas bearing reservoirs (Law, et al., 1989).
f. Age and lithologies	The Upper Cretaceous Medicine Bow, Lewis and Mesaverde formations consist of marine dark, organic rich shales. The Eocene-Paleocene Hanna and Ferris formations consist of organically rich lacustrine shale, coals and fluvial sandstones.
g. Rock extent/quality	Source and reservoir rocks extend throughout the basin.
h. Potential reservoirs	Dark, organic-rich marine shales of the Upper Cretaceous Medicine Bow, Lewis and Mesaverde formations, and organic-rich lacustrine shale, coals and fluvial sandstones of the Eocene-Paleocene Hanna and Ferris formations.

- i. Major traps/seals** Most of the known traps are structural closures around the edges of the basin (Matson, 1984a, b). Several structural/stratigraphic traps are also present (Porter, 1979a, b; McCaslin, 1978). Stratigraphic traps may be present in the deeper part of the basin, in low permeability possibly overpressured Eocene, Paleocene and Upper Cretaceous rocks (Matson, 1984a, b). Major seals are the black/dark shales of the Cretaceous (Mowry, Steele, Thermopolis, Mesaverde), Eocene and Paleocene.
- j. Petroleum generation/migration models** The oil generation window determined from time-temperatures index calculations is at 7216 ft to 11,480 ft in the basin center. Hydrocarbon generation began near 80 Ma at the base of the Late Cretaceous section in the Hanna basin. Transformation models show that the source rocks generated and expelled hydrocarbons very quickly. The Hanna basin is not generating any significant amounts of hydrocarbons at present. The zone of maximum source rock expulsion is modeled at 8200 ft in the center of the basin.
- k. Depth ranges**
- l. Pressure gradients** In the Hanna #1 well (Figure 55) from 11,000 ft to 17,000 ft: R_p increased to 1.23 R_p near the bottom of the hole suggesting thermogenic gas generation and overpressuring below 10,000 ft (Perry, 1992). The bottom hole temperature in the Forgoston, Amoco, and Humble wells ranged from 204 to 240° F, suggesting that overpressuring may be present.

Production and Drilling Characteristics:

- a. Important fields/reservoirs** Rock River (discovered 1918): structural trap/asymmetric anticline. Cumulative production past 40 million bbl. Oil was produced from the Cretaceous Muddy, Dakota, Lakota, and Jurassic Sundance Formations.
- Allen Lake (discovered 1918): Muddy Clovely, Sundance. Big Medicine Bow (Steele, Muddy, Sundance, Tensleep Fms.) Cooper Cove, Diamond Ranch (discovered 1980): Steele Fm.
- Chapman Draw (discovered 1982): Morrison Fm. oil and gas. Simpson Ridge (discovered 1923) Steele Fm.
- b. Cumulative production**

Field Name	Cumulative Oil (bbl) (6/98)	Cumulative Gas (MCF) (6/98)
Rock River	43,550,000	9,838,602
Allen Lake.....	1,768,000
Big Medicine Bow.....	8,796,976	13,712,086
Chapman Draw.....	8,095	816,544
Simpson Ridge	277,074	2,523,981

**Economic
Characteristics:**

a. Inert gas content

b. Recovery

c. Pipeline infrastructure Major gas pipelines run west and south of the Hanna basin to transport gas from the Greater Green River basin and other gas fields in the Rocky Mountain Region.

**d. Exploration maturity
relative to other basins** Mature

e. Sediment consolidation

**f. Porosity/completion
problems**

g. Permeability

h. Porosity

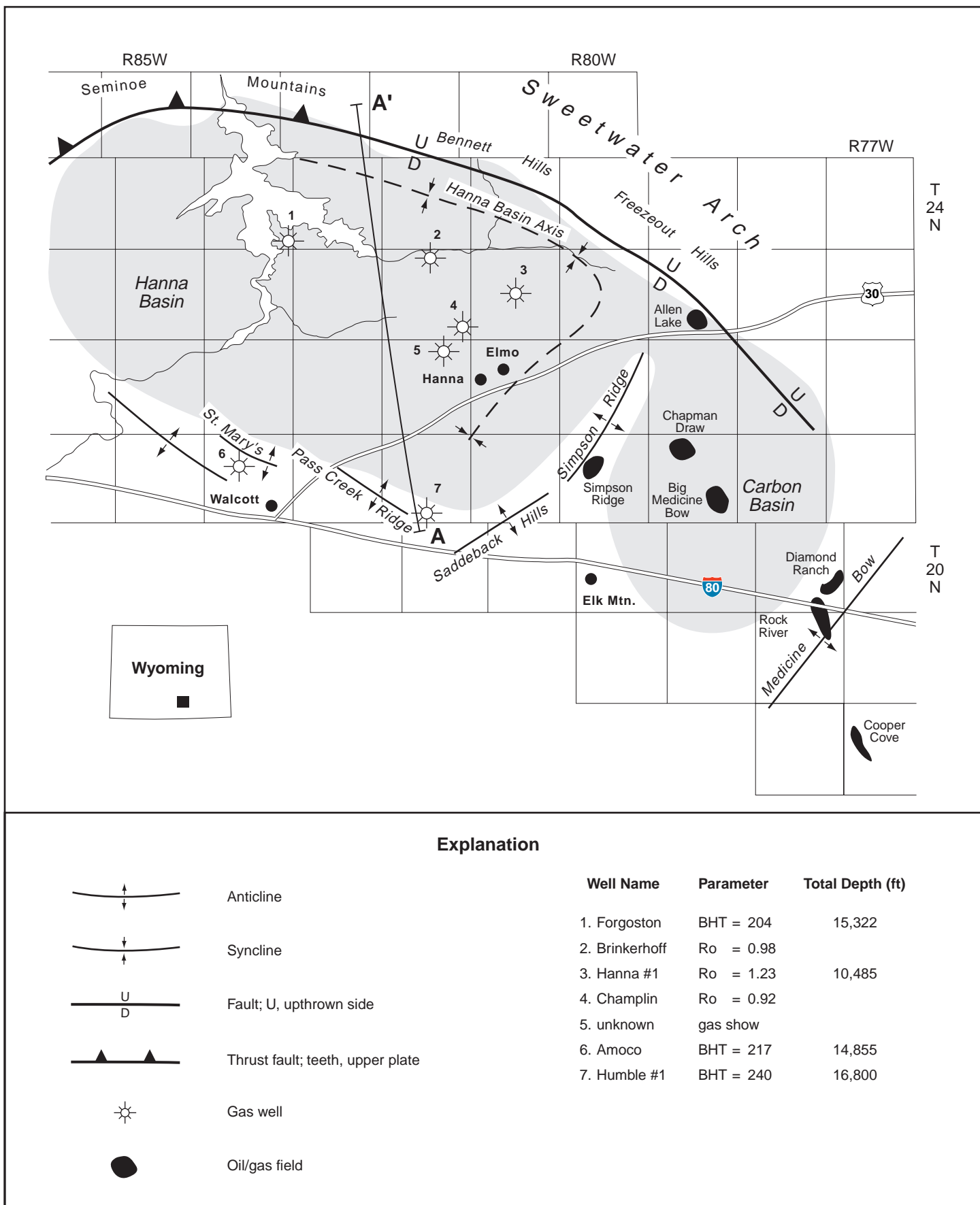

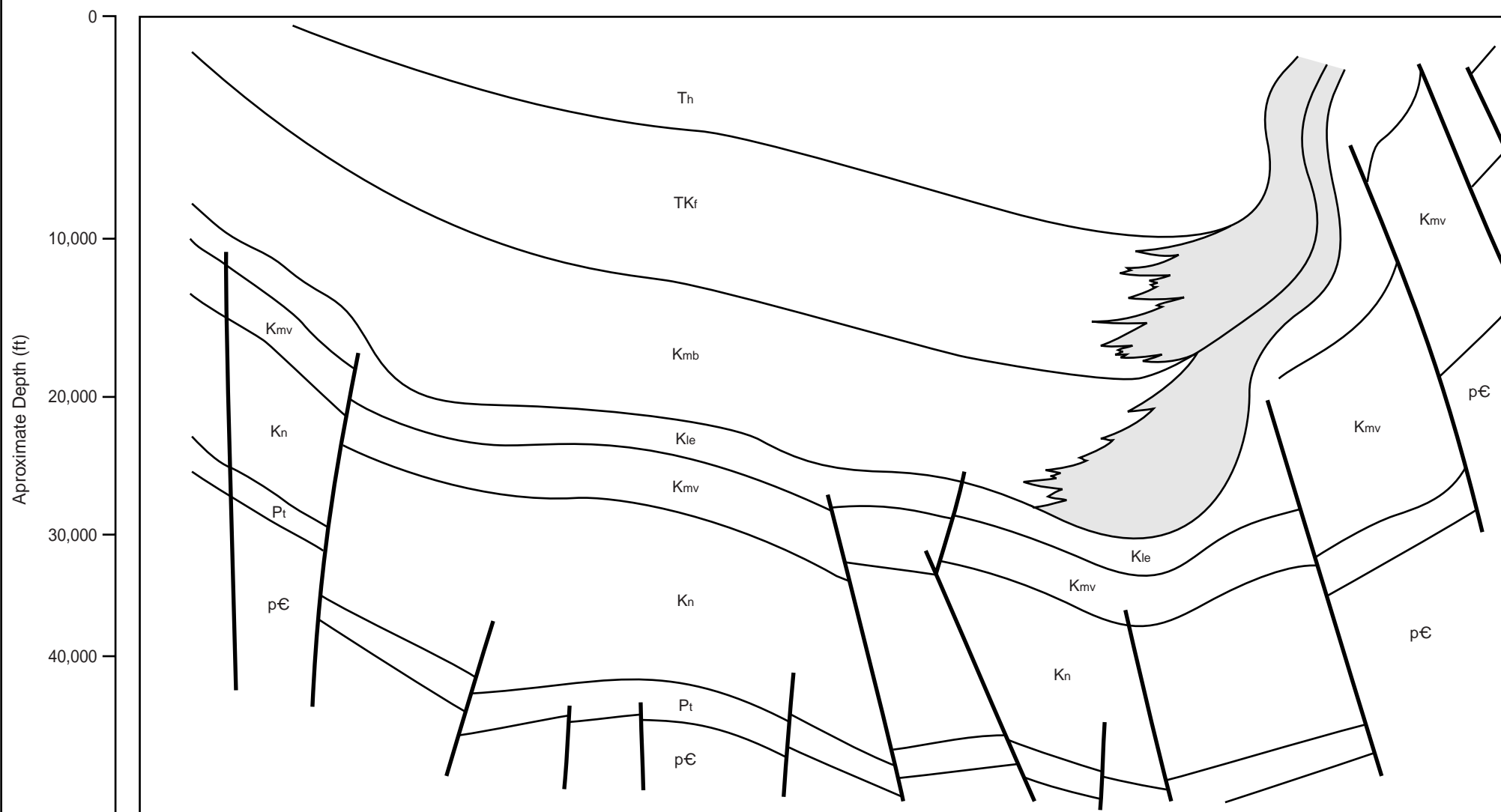


Figure 55: Index map of the Hanna Basin, Wyoming, showing geologic structure, oil and gas fields, wells, relevant gas data, and location of cross section A-A' (Figure 56). After Kaplan and Skeen (1985).

A  Humble Oil No. 1 (*Pass Creek Ridge unit*)

A'



Explanation

Th Hanna Formation
 TKf Ferris Formation
 Kmb Medicine Bow Formation
 Kle Lewis Shale

Kmv Mesaverde Formation
 Kn Niobrara Formation
 Pt Tensleep Formation
 pE Precambrian rocks, undifferentiated

0 5
 Scale (miles)


 Coarser near-shore facies

Figure 56. Geologic cross section A-A' across Hanna Basin. **Figure 55** shows location of cross section. After [Kaplan and Skeen \(1985\)](#).














Age	Unit	Lithology	Avg. Thickness	Hydrocarbon Potential
Tertiary	Hanna	siltstone, silty sandstone, and shale; carbonaceous shale underlying coal beds	19,800 ft	
	Ferris			
Upper Cretaceous	Medicine Bow	continental silty sandstone, and shale; with carbonaceous shale and coal; minor conglomerate	6,000 ft	   
	Lewis	dark gray marine shale	2,100 ft	
	Mesaverde	upper: nearshore silty sandstone, shale, carbonaceous shale, coal lower: marine shale, silty sandstone	2,600 ft	
	Steele	dark gray siltstone, shale; some limited silty sandstone	3,000 ft	
	Niobrara	chalky shale and non-calcareous shale; limited siltstone	1,200 ft	
	Frontier	marine shale and siltstone	800 ft	
Lower Cretaceous	Mowry	black, siliceous shale	200 ft	  
	Muddy	sandstone and silty sandstone; shale	63 ft	
	Thermopolis	dark gray shale; bentonite	80 ft	
	Cloverly	fine-grained silty sandstone; siltstone and shale	200 ft	
Jurassic	Morrison	silty sandstone, shale; occasional carbonaceous shale	375 ft	
	Sundance	silty sandstone, shale; and infrequent oolitic limestone	300 ft	
Triassic	Chugwater	red siltstone, silty sandstone, and shale	700 ft	
Permian	Goose Egg	interbedded red shale, siltstone, limestone, and gypsum	400 ft	
Pennsylvanian	Tensleep (Casper)	silty sandstone; large cross-beds in places; shale, dolomite, anhydrite	400 ft	
	Amsden	shale, silty sandstone, minor limestone, siltstone	300 ft	
Mississippian	Madison	limestone and dolomite throughout; limited shale; siltstone at base	500 ft	
Cambrian	Flathead	transgressive silty sandstone, siltstone, and shale	65 ft	
Precambrian		schists, gneisses, and migmatites of Archean Age; intrusive granites		
<div> Oil</div> <div> Gas</div>				

Figure 57: Stratigraphic chart of units present in the Hanna Basin, Wyoming, showing hydrocarbon potential. After [Kaplan and Skeen \(1985\)](#).

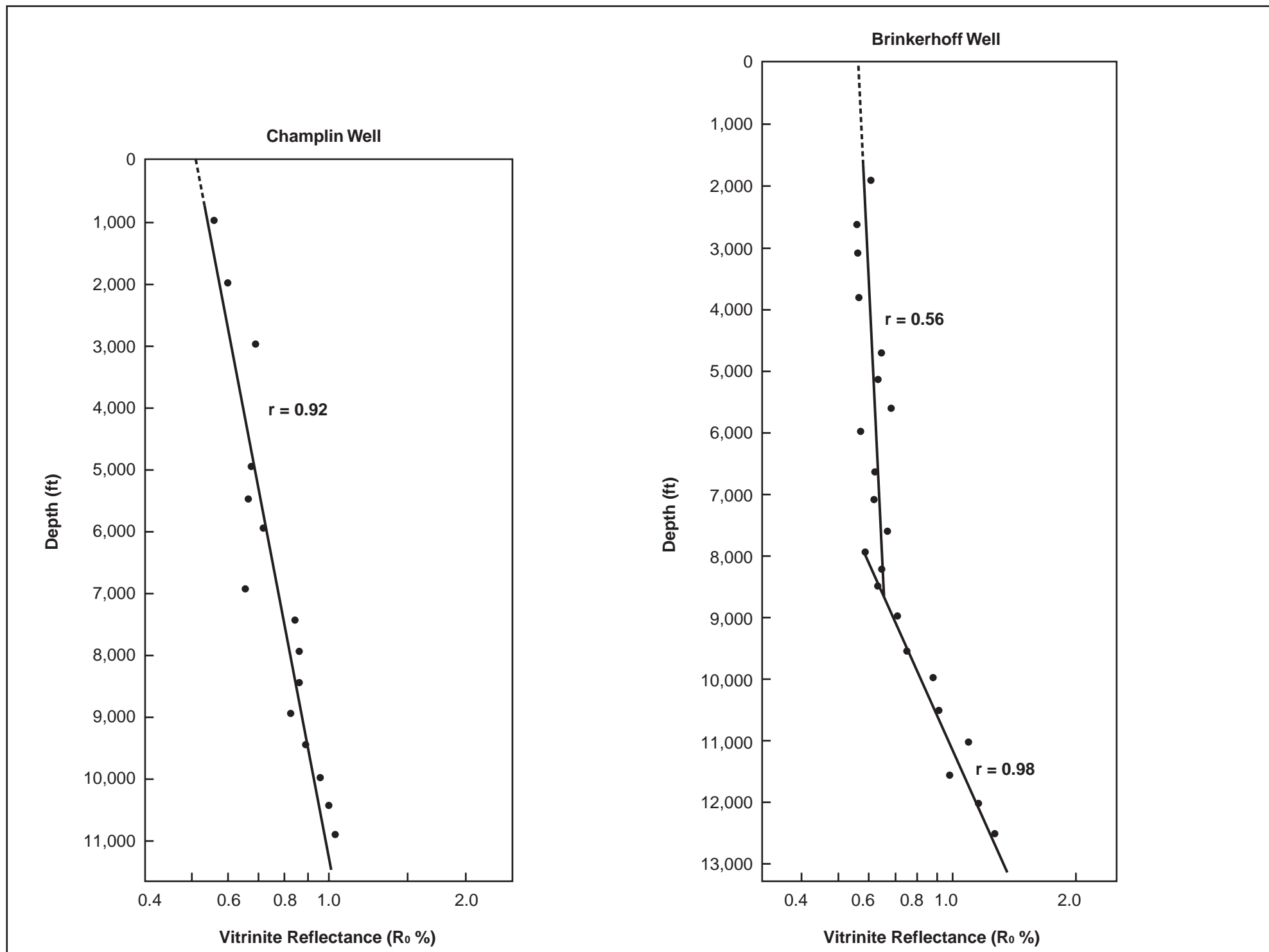


Figure 58. Down-hole vitrinite reflectance profiles from the Champlin and Brinkerhoff wells (see [Figure 55](#) for borehole locations). After [Bierei \(1987\)](#).

HORNBROOK BASIN/MODOC PLATEAU

GEOLOGIC SETTING

The Hornbrook Basin is located in the northeast corner of California and south-central Oregon, and is bounded on the west by the Klamath Mountains ([Figure 59](#)). The Cascade Mountains and the central Oregon volcanic plateaus form the basin's northern boundary. The basin becomes progressively more block-faulted eastward, eventually converging with the Basin and Range. The southern boundary stretches across part of the Basin and Range, the northern end of the Sierra Nevada, the Sacramento Valley, and the Klamath Mountains. The Cascades overlap part of the basin, dividing the Shasta Valley on the west from the Modoc Plateau to the east.

Potential source and reservoir strata in the basin include the Upper Cretaceous Hornbrook Formation and the overlying Upper Cretaceous-Eocene Montgomery Creek Formation ([Figures 60 and 61](#)). Deposition of the Hornbrook occurred in a large, relatively undeformed basin called the "Hornbrook Basin." This basin probably extended beyond the present limits, and probably connected with the Sacramento/Great Valley basins to the south and to the Ochoco Basin northeast in central Oregon. Some Hornbrook strata may have continuity with the Great Valley Sequence. The Hornbrook Formation derives mostly from debris shed from the Klamath Mountains and rests unconformably on pre-Cretaceous metamorphic and igneous basement ([Figure 61](#)). The basal unit is a marine to marginal-marine conglomerate. The formation includes several fining-upwards marine sequences, and the uppermost unit is a 2,600 ft-thick marine shale. At the type section, the Hornbrook has a thickness of 4,200 ft ([Nilsen, 1984b](#)).

The Montgomery Creek Formation also contains much organic shale and siltstone, although deposition occurred mostly in a braided stream, non-marine environment ([Higinbotham, 1986](#)).

[Erskine et al. \(1984\)](#) measured the integrated potential of the basin and deduced that non-magnetic strata (principally Hornbrook and lower Montgomery Creek rocks) thicken eastward under the Cascade Range volcanics and the basalts of the Modoc Plateau ([Figure 60](#)). They projected a thickness of 16,000 ft for this sequence of sedimentary strata. [Erskine's](#) findings suggest the Hornbrook basin formed by uplift of the Klamaths during the Nevadan orogeny, and that it may be as relatively undeformed beneath the Modoc basalts as is the Upper Cretaceous Great Valley Sequence to the south. The basin continued to fill without significant tectonic interruption until the onset of Basin and Range deformation in the middle Miocene. Thereafter, horst-and-graben structures developed in the eastern Modoc Plateau. Thick plateau basalts covered the basin in the middle Miocene and early Pliocene. Cascade volcanism affected the west-central part of the original basin from the late Pliocene to the present.

HYDROCARBON PRODUCTION

Most oil, water and geothermal wells drilled to a depth of 500 ft or greater generally have had gas shows. One operator drilled three wells to 1,200 ft near the north end of Honey Lake and found flow rates of 200 to 450 MCFD, probably originating from a Pliocene lacustrine sand. The wells never produced commercially. [Montgomery \(1988a\)](#) noted that the Klamath 1 Kuck well in northeastern Siskiyou County had oil shows from two Upper Cretaceous sands, but ultimately produced only salt water ([Figure 59](#)).

EVIDENCE FOR BASIN-CENTERED GAS

Several lines of evidence possibly indicate basin-centered gas in the Hornbrook Basin:

- 1) gas seeps and a non-commercial gas field;
- 2) source rocks capable of generating gas; and
- 3) a possible 16,000-ft thick section of “non-magnetic sedimentary rock.”

Total organic carbon (TOC) values for the Hornbrook Formation range from 0.1 to 1.2 wt%, and average 0.52 wt% (Figure 62) (Law et al., 1984). Figure 62 shows that vitrinite reflectance of samples taken along the Interstate 5 corridor ranges from 0.40 to 0.83.

Potential source rocks include coal and coal-bearing shales within the Blue Gulch Mudstone and Dutch Creek Siltstone members of the Hornbrook Formation (Keighin and Law, 1984), and coal-bearing flood-plain and marsh mudstones and lacustrine deposits of the upper Cretaceous to Eocene Montgomery Creek Formation (Higinbotham, 1986). Some of these sediments crop out in the Shasta Valley and in other parts of the western basin. The units dip generally eastward to a depth of 15,000 ft in the central Modoc Plateau. Thus, most of the source rocks probably lie at depths from 15,000 to 31,000 ft in much of the basin. At these depths the most likely hydrocarbons would be thermally generated natural gas. Law et al. (1984) noted the kerogen is Type III and would probably produce gas and little or no oil.

KEY ACCUMULATION PARAMETERS

Identification

Shasta - Yreka Valley and Modoc Plateau, Northeastern California, Central Southern Oregon. Possible Cretaceous to Upper Tertiary Overpressured Gas Play.

Geologic Characterization of Accumulation:

- a. Source/reservoir** **Potential Source Rocks:** Slope shales of the Hornbrook Fm. Coal and coal bearing shales within the Blue Gulch Mudstone Member, and the Dutch Creek Siltstone Member of the Hornbrook Fm ([Keighin and Law, 1984](#)).
Coal-bearing flood plain, marsh mudstones and lacustrine deposits within the upper Cretaceous to Eocene Montgomery Creek Fm ([Higinbotham, 1986](#)). Possible, poorly-known mid-Mesozoic dark brown to black shales underlying the Klamath Mountains.
- b. Total Organic Carbons (TOCs)** Late Cretaceous Hornbrook Fm. = 0.1 to 1.2 Wt % organic carbon, averaging .52% TOC; these are surface samples that may have been strongly oxidized, so TOC may be conservative ([Law et. al. 1984](#)).
- c. Thermal maturity** Surface samples are generally marginally mature to mature ([Law et al., 1984](#)).
- d. Oil or gas prone** Gas prone; kerogen is generally Type III; will probably produce gas and little or no oil ([Law et al., 1984](#)).
- e. Overall basin maturity** Unknown; deeper parts of basin in the central and eastern Modoc Plateau may be mature to overmature. Those areas directly overlain by the Cascade Volcanic Range and the Plateau Volcanics surrounding the Medicine Lake Caldera to the east may be overmature.
- f. Age and lithologies** Primary exploration target strata range in age from Late Cretaceous through the Miocene.
- g. Rock extent/quality**
- h. Potential reservoirs** **Potential Reservoir Rocks:** Montgomery Creek Fm, fluvial, Eocene, ([Higinbotham, 1986](#)). Hornbrook Fm., Late Cretaceous ([Nilsen, 1984a; 1984b](#)). Interbedded mid to late Cenozoic volcanic and lacustrine rocks, similar to Rattle Snake Hills Gas Field (abandoned), Benton County, Washington ([Hammer, 1934](#)).
- i. Major traps/seals** Traps may be of all types (structural and/or stratigraphic).
- j. Petroleum generation/migration models** [Weimer \(1996\)](#) “cooking pot model”
- k. Depth ranges** Potential reservoir rocks occur from the surface in the Shasta Valley and Ashland, Oregon area ([Figure 62](#)), to an approximate depth of 9 km. Also in the eastern Modoc Plateau, near the transition with the Basin and Range Province ([Fuis and Zucca, 1984; Erskine et al., 1984](#)).

I. Pressure gradients

Production and Drilling Characteristics:

- | | |
|--------------------------------|------|
| a. Important fields/reservoirs | none |
| b. Cumulative production | none |

Economic Characteristics:

- | | |
|--|--|
| a. Inert gas content | Unknown though possible; other basins with a high volcanic and intrusive content often contain higher than normal CO ₂ , helium, and other inert components. |
| b. Recovery | |
| c. Pipeline infrastructure | P G & E has a 36-in gas transmission line through the area. Additional lines are being built or are planned through the area to transport Canadian gas to the major central and southern California markets. |
| d. Exploration maturity relative to other basins | Immature, a frontier basin. |
| e. Sediment consolidation | Target formations are very competent. |
| f. Porosity/completion problems | Hornbrook Fm permeability measured from surface samples is low, generally less than 1.2 md. However, this is an active tectonic area, and may have well-developed fracture porosity (Keighin and Law, 1984). |
| g. Permeability | |
| h. Porosity | |

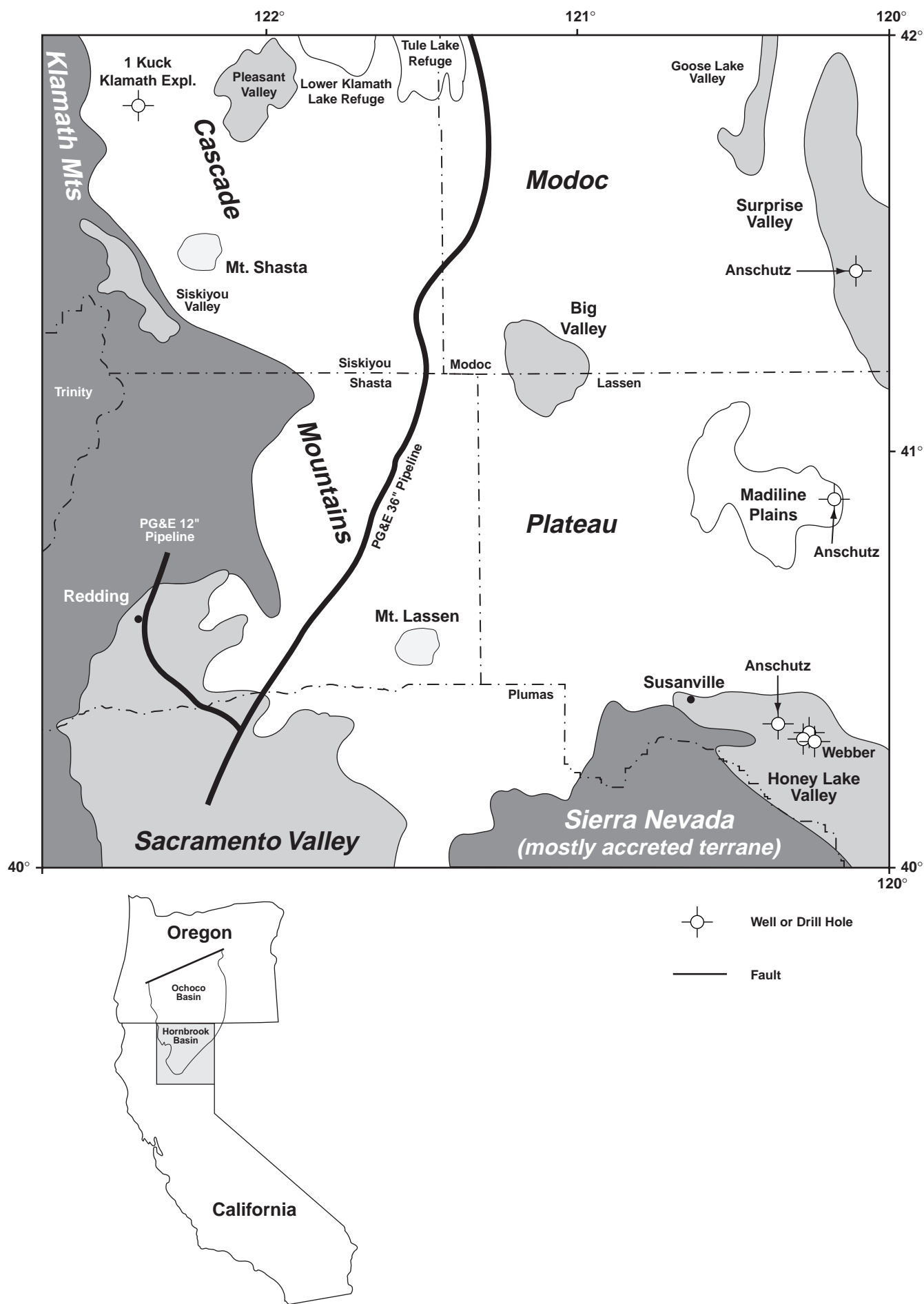


Figure 59. Generalized geologic map showing natural gas pipelines and oil and gas exploration wells in the Hornbrook basin and Modoc Plateau area, northeastern California. After [Nilsen \(1984b\)](#) and [Montgomery \(1988a\)](#).

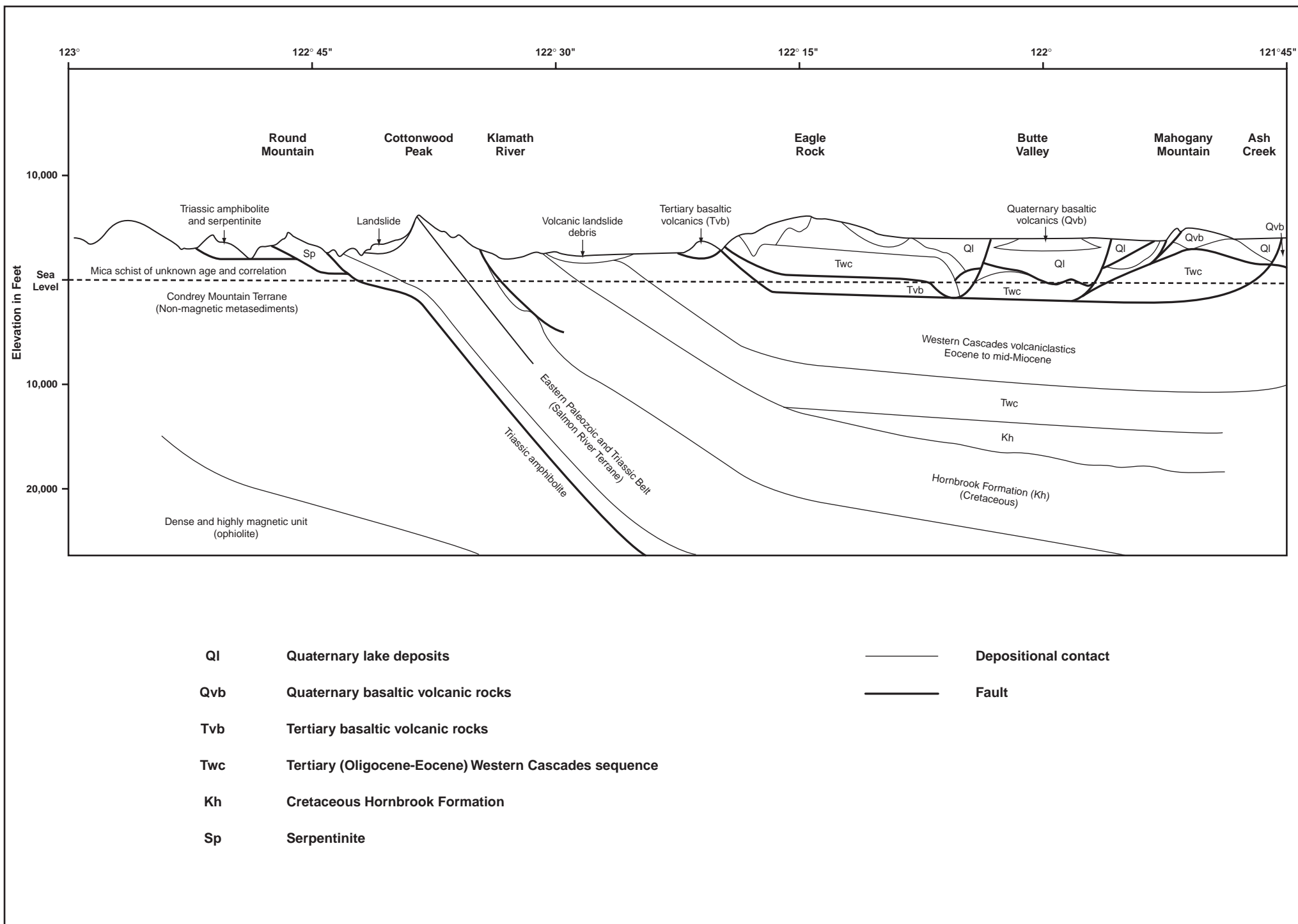


Figure 60. Cross section derived from integrated potential field model of the western part of the Hornbrook Basin-Modoc Plateau region of Northeastern California. West-east section located approximately at latitude 41° 55" North. After [Erskine et al. \(1984\)](#).

System	Series	Lithology	
Quaternary	Holocene	Basalt; Lacustrine and Fluvial Sediments	
Tertiary	Pleistocene	Alturas Formation (Basalt, Lacustrine Sediments)	
	Pliocene		
	Miocene	Cedarville Series (Basalt, minor Rhyolite, Lacustrine Sediments)	
	Upper Oligocene		
	Lower Oligocene	Weaverville Formation (Trinity County) (Non-marine Sandstones and Shales)	
	Upper-Middle Eocene	Upper Montgomery Creek Formation (and equivalent) (Non-marine, Fluvial Sandstones and Shales)	
Upper Cretaceous	Maestrichtian	Lower Montgomery Ck. ? ? ?	
	Campanian		? ? ?
	Santonian	Hornbrook Formation (Marine)	Redding Formation (Marine)
	Coniacian		
	Turonian		
	Cenomanian		
Pre-Cretaceous		Klamath-Sierra Nevada Metamorphic and Intrusive Rocks	

Figure 61. Stratigraphic column of the Hornbrook Basin, Upper Cretaceous to Recent. After [Montgomery \(1988a\)](#).

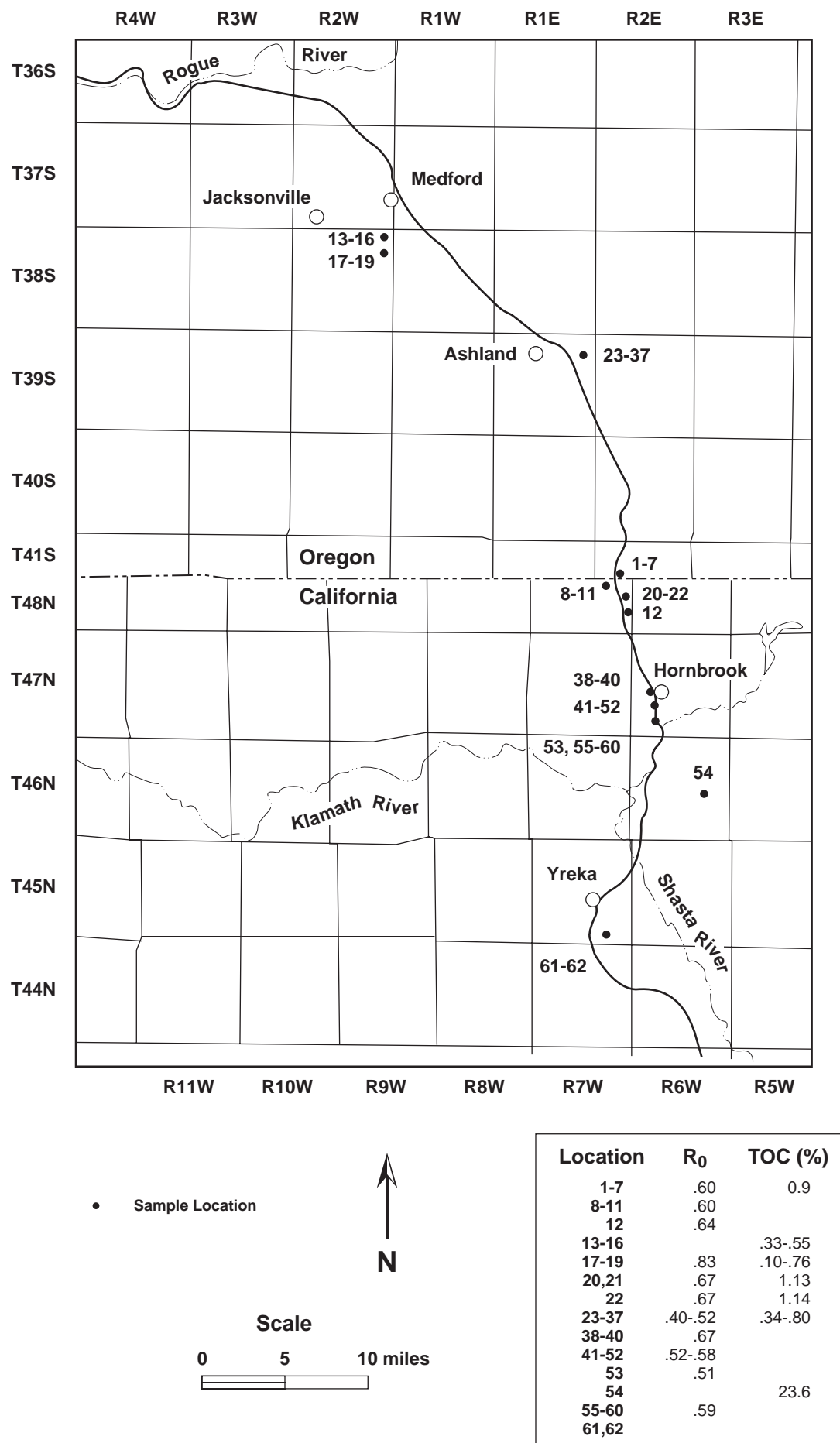


Figure 62. Location of Hornbrook Formation source rock samples showing vitrinite (R₀) and total organic carbon (TOC) values. After [Law et al. \(1984\)](#).

LOS ANGELES BASIN

GEOLOGIC SETTING

The present day Los Angeles Basin is a deep structural depression about 50 miles long and 20 miles wide located on the west coast of southern California (Figure 63). The Santa Monica and San Gabriel Mountains form the northern boundary and the Santa Ana Mountains mark the eastern edge. The Pacific Ocean limits the basin on the west and the south. The basin contains at least 24,000 ft of Late to Middle Miocene and younger marine clastic rocks overlying older Cenozoic sedimentary rocks and Mesozoic basement rocks (Figure 64). There are four large structural blocks in Los Angeles basin—the southwestern, northwestern, central, and northeastern—separated by faults or flexures in the basement rocks (Figure 63). Figure 65 shows the stratigraphic units involved (Yerkes et al., 1965; Beyer, 1996; Brown, 1966). A potential basin center gas accumulation may be present in the central block and within the northwest-trending Central Syncline (Figure 63).

Sedimentary rocks range in age from latest Cretaceous to Holocene and divide into two groups: a "pre-basinal" suite of Upper Cretaceous to Lower Miocene rocks, and "basinal" marine sediments deposited in a rapidly subsiding trough since Middle Miocene time (Yerkes et al., 1965).

The geotectonic history of the Los Angeles Basin follows a constant-motion plate-tectonic model, which links movements of the San Andreas fault to the Cenozoic sea floor spreading in the northeastern Pacific (Campbell and Yerkes, 1976). The basin formed by Middle Miocene to Early Pliocene extension, strike-slip faulting and block rotation, and Late Pliocene to Recent north-south compression (Beyer, 1996). Extensive igneous flows, intrusive rocks, and tephra were emplaced within and around the basin during Late Miocene.

HYDROCARBON PRODUCTION

Oil production from the basin has continued since the 1880s. The Los Angeles Basin ranks first world-wide in total discovered oil-in-place per unit volume. The hydrocarbon richness of the basin results from a favorable sequence of events including:

- 1) the deposition of abundant oil-prone organic matter in low oxygen environments,
- 2) rapid burial which preserved the organic matter,
- 3) maturation and expulsion of oil coinciding with trap formation, and
- 4) production of hydrocarbons before uplift and erosion could destroy a significant portion of the reservoirs.

Fifteen of the sixteen largest oil fields, which account for 91% of the basin's total, were discovered before 1933. Significant discoveries include the Beverly Hills, La Cienega, Riviera, and San Vicente fields—all found during the 1960s. Urbanization has constrained exploration. Drilling activity during the last 40 years has averaged just two wells per year. Cumulative production and estimated reserves exceed 9.6 BBO and 8.7 TCFG (Beyer, 1996). All significant gas reserves in the basin have been associated with oil accumulations (Gardett, 1970). Most of the discovered accumulations have been in structural/stratigraphic traps in Miocene and Pliocene turbidite sandstones, ranging from distal turbidite sandstones to proximal conglomeratic sandstones. Several minor reservoirs have been discovered in Pleistocene, Pliocene and middle Miocene sandstones. Reservoir depths range from 900 to 11,900 ft, and thicknesses range from 15 to 1,200 ft. Structure has been the dominant trapping mechanism for discovered hydrocarbons. Traps north and south of the basin center include faulted anticlines, faulted noses, homoclines, domes, and various stratigraphic traps. To date, the basin center area remains undrilled, except for the American Petrofina Core Hole well in the basin center (Stark, 1972; Beyer, 1988).

EVIDENCE FOR BASIN-CENTERED GAS

The American Petrofina Core Hole well bottomed at a depth of 21,215 ft in Delmontian (Upper Miocene to Middle Pliocene) rocks in the basin center syncline (Beyer, 1996). Unfortunately, the well did not reach the Mohnian (Upper Miocene) section, which may be the equivalent of the (late Middle Miocene) Modelo Formation's organic-rich "nodule shale" found elsewhere in the basin (Bostick et al., 1978). Therefore, drilling has not yet confirmed the presence of source and reservoir rocks in the basin center. Shallower wells on the east flank of the Newport-Inglewood zone penetrated interbedded sandstone and shale containing type II kerogen in the lower Mohnian section (Beyer, 1996); the Mohnian rocks may be fractured because of fluid overpressuring during maturation of kerogen in the organic-rich shale. The play, if present, will be in the Lower Mohnian section. Favorable conditions for basin center gas accumulations are present in the Los Angeles basin for the following reasons:

- 1) Thermally mature source rocks (R_o values > than 1.2% and TOC's of 1-9%) are present in the basin center (Beyer, 1996);
- 2) Abnormally high formation pressures were measured both in the American Petrofina Core Hole in the basin center syncline, and in the Standard Oil of California well (0.72 psi/ft) located northeast of the basin center (Bostick et al., 1978; Beyer, 1988);
- 3) High reservoir temperatures ranging from 205 to 304° F were measured in the central basin syncline (8,900 to 15,500 ft);
- 4) Hydrocarbons are present in the basin center—the American Petrofina Core Hole well yielded 43° API gravity oil, with a high gas-oil ratio at 21,215 ft depth (Beyer, 1996); and
- 5) A thick section of Upper Miocene (Mohnian) rocks ranging in thickness from 3,000 to 7,000 ft may be present in the basin center (Beyer, 1996).

KEY ACCUMULATION PARAMETERS

Identification

Pacific Coast- Los Angeles Basin, California. Middle to Late Miocene and Early Pliocene age rocks (upper Mohnian, Delmontian and "Repettian" stages).

Geologic Characterization of Accumulation:

- a. Source/reservoir** **Southwestern shelf:** the organic-rich basal "nodular shale" of late Middle Miocene Modelo Formation, sourcing the underlying schist conglomerate and the overlying marine sandstone reservoirs ([Bostick et al., 1978](#));
Central syncline: source rocks may occur at a lower stratigraphic level similar to the "nodular shale" ([Schmoker and Oscarson, 1995](#)).
- b. Total Organic Carbons (TOCs)** 1.0% - 9.0%
- c. Thermal maturity** Type II; $R_o = 0.24-0.89\%$ ([Bostick et. al., 1978](#)), but greater than 1.2% in the American Petrofina Core Hole at 21,215 ft ([Beyer, 1996](#)) (hydrocarbon-rich shales found in the basin may retard or suppress vitrinite reflectance values).
- d. Oil or gas prone** Both oil and gas prone.
- e. Overall basin maturity** Considered mature.
- f. Age and lithologies** Middle to Late Miocene and Early Pliocene rocks (Upper Mohnian, Delmontian and "Repettian" stages). Lithologies are primarily turbidite sandstones, siltstones and shales.
- g. Rock extent/quality** Basin-wide source and reservoir-rock distribution.
- h. Potential reservoirs**
- i. Major traps/seals** Structural in producing fields; basin center traps-unknown but postulated as (1) deep continuous reservoirs without clear boundaries, (2) localized reservoirs where fracturing is a function of lithofacies, (3) reservoirs structurally bounded by faulting or folding. Basin center seals: shales. Also, the presence of laumontite that was reported at depth in the American Petrofina Core Hole well may degrade the quality of the reservoir rocks and help form seals ([Beyer, 1996](#)).
- j. Petroleum generation/migration models** Migration began during early Pliocene or earlier and probably continues today. Migration is not necessary for postulated self sourcing reservoirs.
- k. Depth ranges** 900 to 11,900 ft (producing fields); 21,000 to 24,000 ft in the basin center.
- l. Pressure gradients** Overpressured aqueous pore fluids of 0.72 psi/ft were reported in the Standard Oil of California "Houghton Comm. One" No. 1 well (14,000 ft depth), located northeast of the Central Syncline ([Bostick et al., 1978](#)).

**Production and Drilling
Characteristics:**

- a. Important fields/reservoirs** Wilmington-Belmont (discovered 1932, >2.857 BBO and 1.235 TCFG); Huntington Beach (discovered 1920, >1.138 BBO and 861 TCFG); Long Beach (discovered 1921, >945 MMBO and 1.088 TCFG); Santa Fe Springs (discovered 1919, >634 MMBO and 839 BCFG); Brea-Olinda (discovered 1880, >430 MMBO and 482 BCFG); Inglewood (discovered 1924, >400 MMBO and 285 BCFG); Beverly Hills (discovered 1966, >135.5 MMBO and 202 BCFG); Torrance (discovered 1922 >246 MMBO and 158 BCFG); Richfield (discovered 1919, 203 MMBO and 173 BCFG); and Coyote East (discovered 1911, 122 MMBO and 61 BCFG); data taken from [Beyer \(1996\)](#).
- b. Cumulative production** See **Important fields/reservoirs** above.

**Economic
Characteristics:**

- a. Inert gas content**
- b. Recovery** good
- c. Pipeline infrastructure** Very good; there are numerous gas lines in the basin.
- d. Exploration maturity relative to other basins** mature
- e. Sediment consolidation** Consolidation/porosity reduction occurs with depth of burial.
- f. Porosity/completion problems** No expected completion problems, based on existing field information.
- g. Permeability**
- h. Porosity**

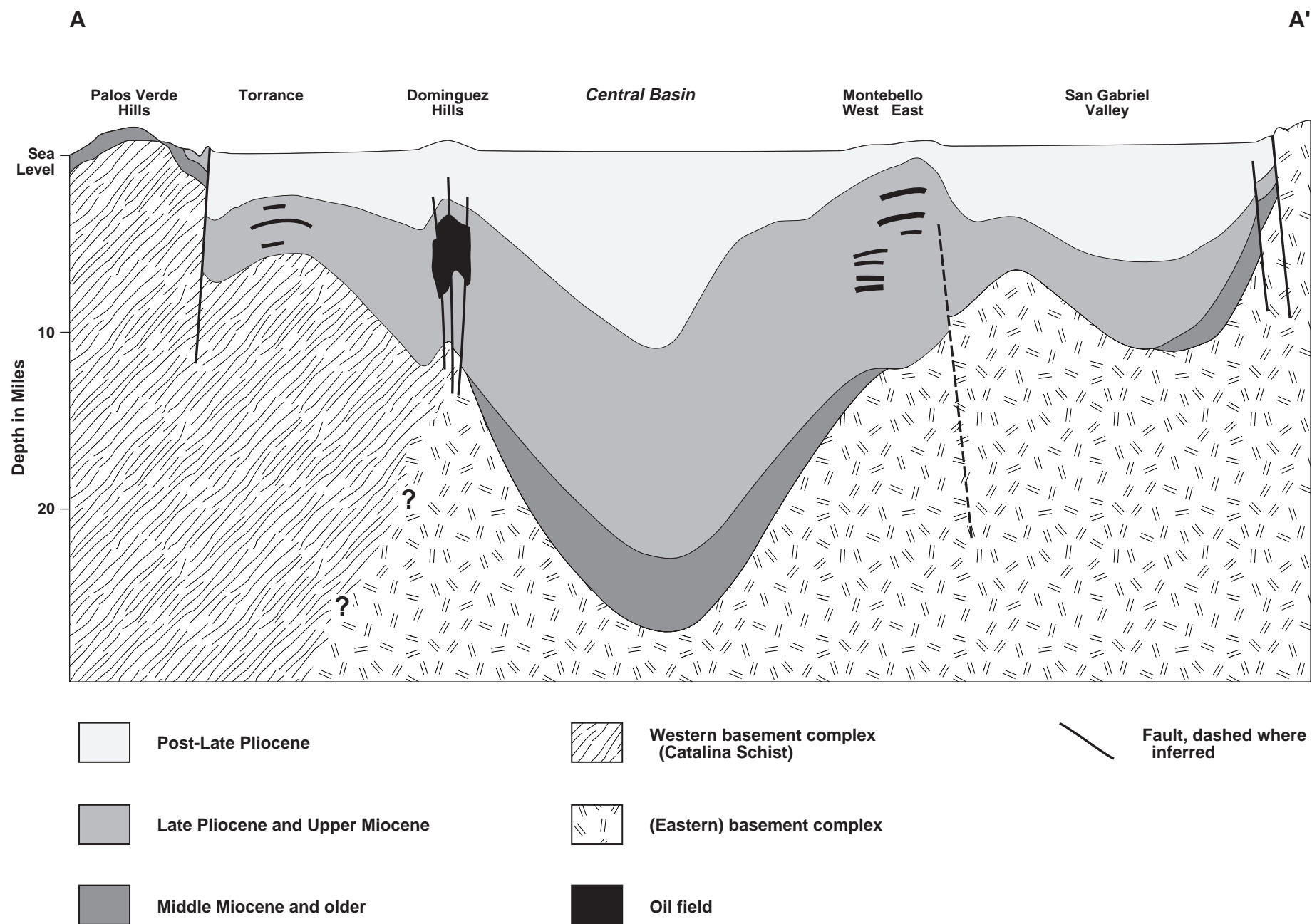


Figure 64. Generalized cross-section A-A' of the Los Angeles basin, California, showing selected oil fields. **Figure 63** shows location of cross section. After [Beyer \(1988\)](#).

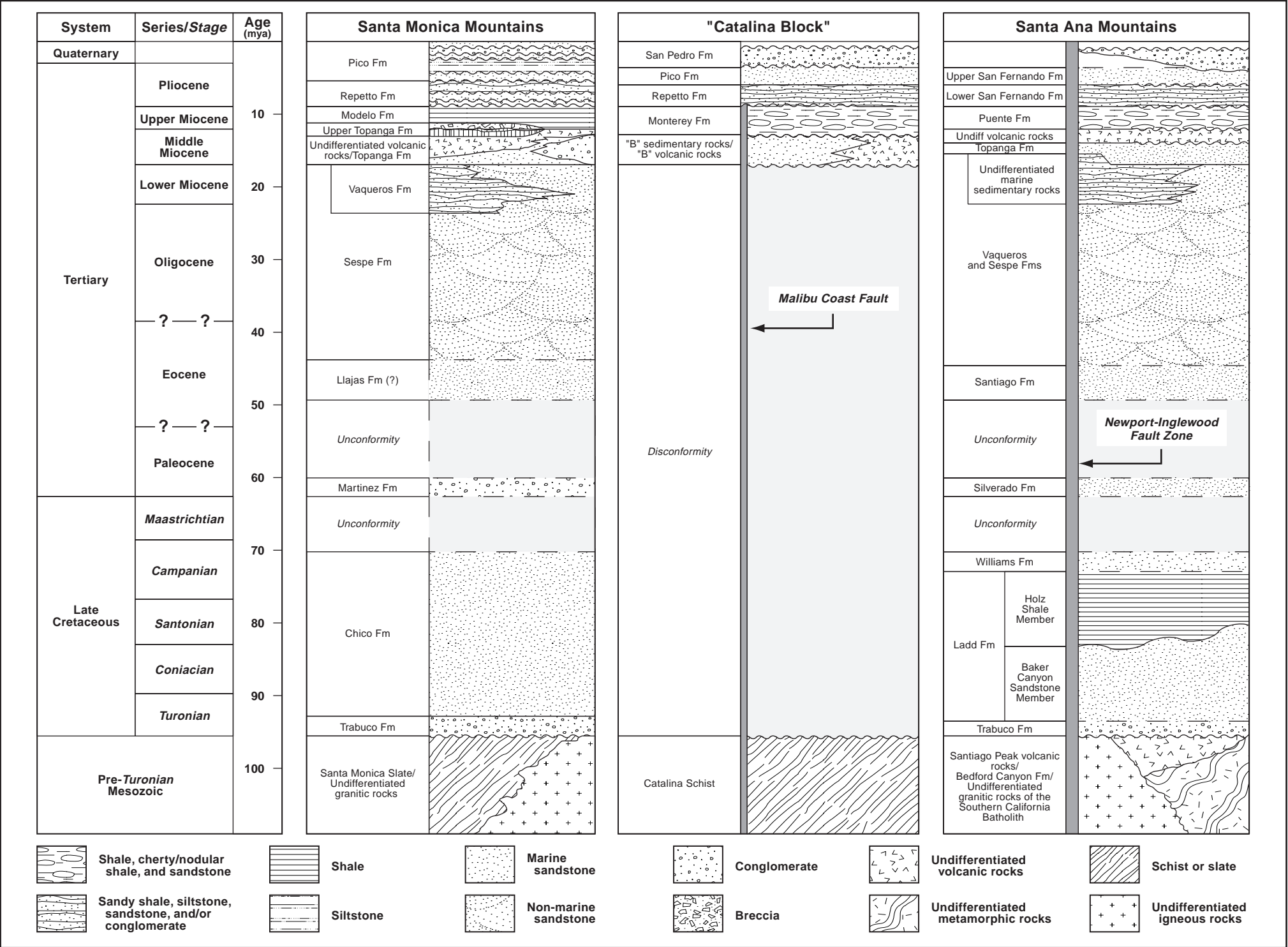


Figure 65. Generalized stratigraphic columns for the Los Angeles basin, California. After [Yerkes et al. \(1965\)](#), and [Campbell and Yerkes \(1971\)](#).

MESOZOIC RIFT BASINS (EASTERN U.S.)

GEOLOGIC SETTING

The Mesozoic rift basins of eastern North America formed in response to the break-up and separation of Pangaea in late Paleozoic to early Mesozoic time. Rift basins formed simultaneously on both the North Atlantic and Euro-African plates (Pyron, 1998). These basins consist of elongate, asymmetric, half-graben structures which contain thick Triassic through lower Jurassic clastic, evaporite and volcanic rocks. The basin fill rests unconformably on crystalline basement formed during the Acadian and Alleghenian orogenies. Sedimentary rock types include reddish-brown mudstones, coarse-grained "border" conglomerates, arkosic sandstones, siltstones, gray-black lacustrine shales, evaporites, and coal. Tholeiitic basalt flows, sills and dikes are also common. On-shore rift basins, both exposed (in the Piedmont and Blue Ridge Provinces) and inferred (in the Coastal Plain), extend from Georgia to Massachusetts and cover about 42,700 square miles (Figure 66). Individual basins range from 24 square miles (Taylorsville basin) to over 3,100 square miles (Newark basin) in area. Offshore basins extend from Nova Scotia to the Florida Panhandle (Figure 67). The rift basins generally trend northeast, approximately perpendicular to the initial rifting of North America and Africa (Klitgord and Behrendt, 1977).

The tectonic history of the basins includes 5 stages:

- 1) Permian through Triassic: crustal thinning along the eastern margin of the North American continent. This is the earliest stage of Pangaea breakup.
- 2) Middle Triassic: rifting and crustal extension. Late Triassic clastic deposition into subsiding basins.
- 3) Early Jurassic: extension and clastic deposition in basins along tholeiitic basalt flows and intrusions.
- 4) Middle Jurassic: sea-floor spreading and development of the Mid-Atlantic ridge system.
- 5) Late Jurassic to present: lithospheric cooling, plate subsidence, and marine transgression with development of a passive continental margin (Schultz, 1988).

The depositional history of a typical onshore Mesozoic rift basin of eastern North America includes four phases:

- 1) Formation of a rift graben along a listric boundary fault. Alluvial fans form along the upthrown walls and coalesce into laterally extensive deposits of conglomerate, and finer-grained sediments near the basin center. Conglomerates interfinger with sandstones and siltstones. Internal basin drainage produces intermittent playas with evaporite deposits.
- 2) Tectonic subsidence of the basin ends. Alluvial fans become reworked; coarse to fine sediments enter from outside the rift structure. Internal drainage results in the formation of a lake in the basin center. Vegetation flourishes along the lake margins and provides organic material for sedimentation. Feeder streams deposit coarse sands and conglomerates interfingered with lacustrine sediments.
- 3) Fluvial and lacustrine sands become reworked and re-deposited parallel to the long axis of the basin. Diabase dikes, sills and sheets intrude along zones of weakness. The magma causes regional heating of the basin and consequent thermal maturation of organic sediments.
- 4) Recent uplifting, tilting, and regional erosion created the present day geology. In many offshore basins, evaporite deposition followed continental deposition. During Cretaceous and Tertiary time, marine sediments covered the continental rocks (Pyron, 1998).

HYDROCARBON PRODUCTION

There is no hydrocarbon production from any Mesozoic rift basin in the eastern U.S. Seventy years of exploratory drilling in the rift system has yielded numerous shows of oil and gas but no commercial hydrocarbons.

EVIDENCE FOR BASIN-CENTERED GAS

Other Mesozoic rift basins are productive, including the Ghadames basin in Algeria (Northeast Africa), the Cuyo basin in Argentina (South America), the North Sea (Europe), and the Jeanne d'Arc basin (Canada). Rift basins offer attractive exploration targets because the cycle of rifting, sedimentary fill and igneous activity provides reservoirs, source rocks and thermal maturity.

Significant potential exists for basin-centered gas accumulations within thick lacustrine mudstones, black shales, siltstones, and sandstones in the deep parts of the eastern U.S. rift basins. Geochemical data, including total organic carbon (TOC), thermal alteration index (TAI), vitrinite reflectance (R_o), and Tmax measurements, indicate the basins are thermally mature.

The Newark basin in central New Jersey and southeastern Pennsylvania may contain significant gas reserves. **Figure 67** includes maps depicting the geology and structure of this basin; **Figure 68** shows basin stratigraphy in three locations. The Newark forms a part of a larger rift system that also incorporates the Gettysburg and Culpeper basins and extends from New Jersey southwest to Virginia. The exposed sedimentary section along this system is over 25,000 ft thick and appears gas prone. The Newark has had only three exploratory wells drilled. One well reached a depth of 10,500 ft and encountered gas shows within a 3,000-ft section of fractured lacustrine shale.

The Danville basin (Virginia-North Carolina) is also gas prone with a 9840 ft thick sedimentary section. The Hartford basin appears to be oil prone ([Hubert et al., 1992](#); [Schultz, 1988](#); [Kotra et al., 1988](#)).

Exploration may identify productive basins where suitable reservoir rocks occur. Basins with thin sedimentary sections, such as the Richmond and Taylorsville, would be less attractive exploration targets.

KEY ACCUMULATION PARAMETERS

Identification	Eastern U.S. onshore Mesozoic basins; upper Triassic through lower Jurassic continental clastic and carbonate rocks.
Geologic Characterization of Accumulation:	
a. Source/reservoir	Late Triassic early Jurassic thick sequences of organic black and gray shales and black siltstones deposited along the centers of the basins.
b. Total Organic Carbons (TOCs)	Newark: 0.5-6.0% (lacustrine black shales); Hartford: 0.4-3.5% (lacustrine black shales); Culpeper: 0.4-8.0% (lacustrine black shales); Danville: 0.1-2.4% (black shale/coal); Deep River: up to 35% (black shale/coal); Richmond: up to 40% (black shale/coal) (Schultz, 1988 ; Pratt and Burruss, 1988).
c. Thermal maturity	Kerogen Type: Hartford and Richmond basins: lacustrine algae (Type 1) and mixed lacustrine algae/terrestrial plant debris (Type 2); Newark, Culpeper and Dan River basins: mixed (Type 2) (Kotra et al., 1988 ; Schultz, 1988). Thermal alteration index (TAI): Newark (3+) and Danville basins (4.0); Hartford, Deep River and Richmond basins (2.5-to 3.0); Vitrinite reflectance (Ro): Hartford basin 0.5-1.0; Danville basin 2.15. Tmax (°C): Newark basin 426-443; Danville basin 400+; Hartford, Deep River, Richmond, Taylorsville basins 441-455 (Kotra et al., 1988 ; Pratt et al., 1988).
d. Oil or gas prone	Both oil and gas prone: Newark and Danville basins-gas prone. Hartford, Deep River, Richmond basins-oil prone.
e. Overall basin maturity	Highly variable. Extensive igneous activity and high heat flow cooked many of the lacustrine shales and coals in the southern basins.
f. Age and lithologies	Upper Triassic through lower Jurassic.
g. Rock extent/quality	Basin-wide source and reservoir-rock distribution.
h. Potential reservoirs	Hartford: migrated bitumen on sandstone outcrops and in fractures; no drilling; Texaco seismic surveys in late 1985. Newark: migrated bitumen on sandstone outcrops and in fractures; North Central 1 KCI Cabot 1985 test to 10,500 ft reported gas shows in 3000 ft thick organic shale section. Gettysburg: 4 dry holes; one well reached 7000 ft to Lower Cambrian clastic rocks (1960s). Culpeper: 2 wells, 2.5 bbl oil recovered in tests; bitumen on outcrops (1914, 1916). Richmond: about 15 holes from 1970-1988, both deep and shallow; oil and gas shows; some oil recovered. Taylorsville: about 6 holes in the 1980s; rumored to have oil and gas shows. Dan River: about 3 tests in the 1970s-1980s; oil and gas shows with some oil recovered; oil in black shales. Farmville: one hole with oil and gas shows. (Schultz, 1988 ; Pyron, 1988)
i. Major traps/seals	Interbedded shales, siltstones and sandstones of alluvial fans and lacustrine sediments.

- j. Petroleum generation/migration models** Oil and gas shows and bitumen in fractures are evidence of hydrocarbon generation and migration in these basins.
- k. Depth ranges** 10,000-20,000 ft
- l. Pressure gradients**

Production and Drilling Characteristics:

- a. Important fields/reservoirs** Potential reservoirs/fields unknown in these basins: Newark, Culpeper, Richmond, Taylorsville, Dan River, Farmville.
- b. Cumulative production**

Economic Characteristics:

- a. Inert gas content**
- b. Recovery**
- c. Pipeline infrastructure** very good
- d. Exploration maturity relative to other basins**
- e. Sediment consolidation** Consolidation/porosity reduction occurs with depth of burial.
- f. Porosity/completion problems**
- g. Permeability**
- h. Porosity**

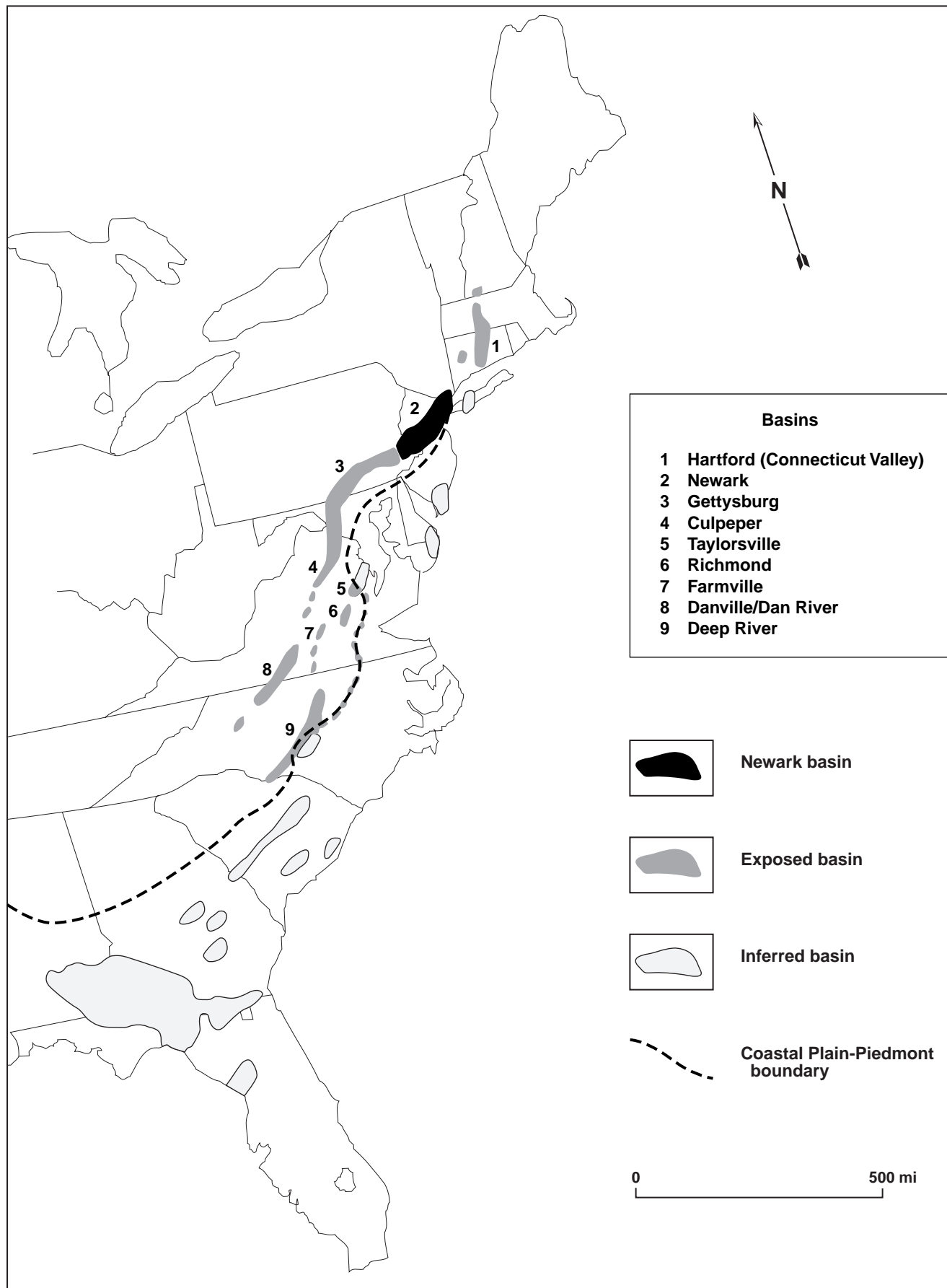


Figure 66. Index map of exposed and inferred Mesozoic basins of eastern North America and the Coastal Plain-Piedmont boundary. After [Manspeizer and Olsen \(1981\)](#), and [Schultz \(1988\)](#).

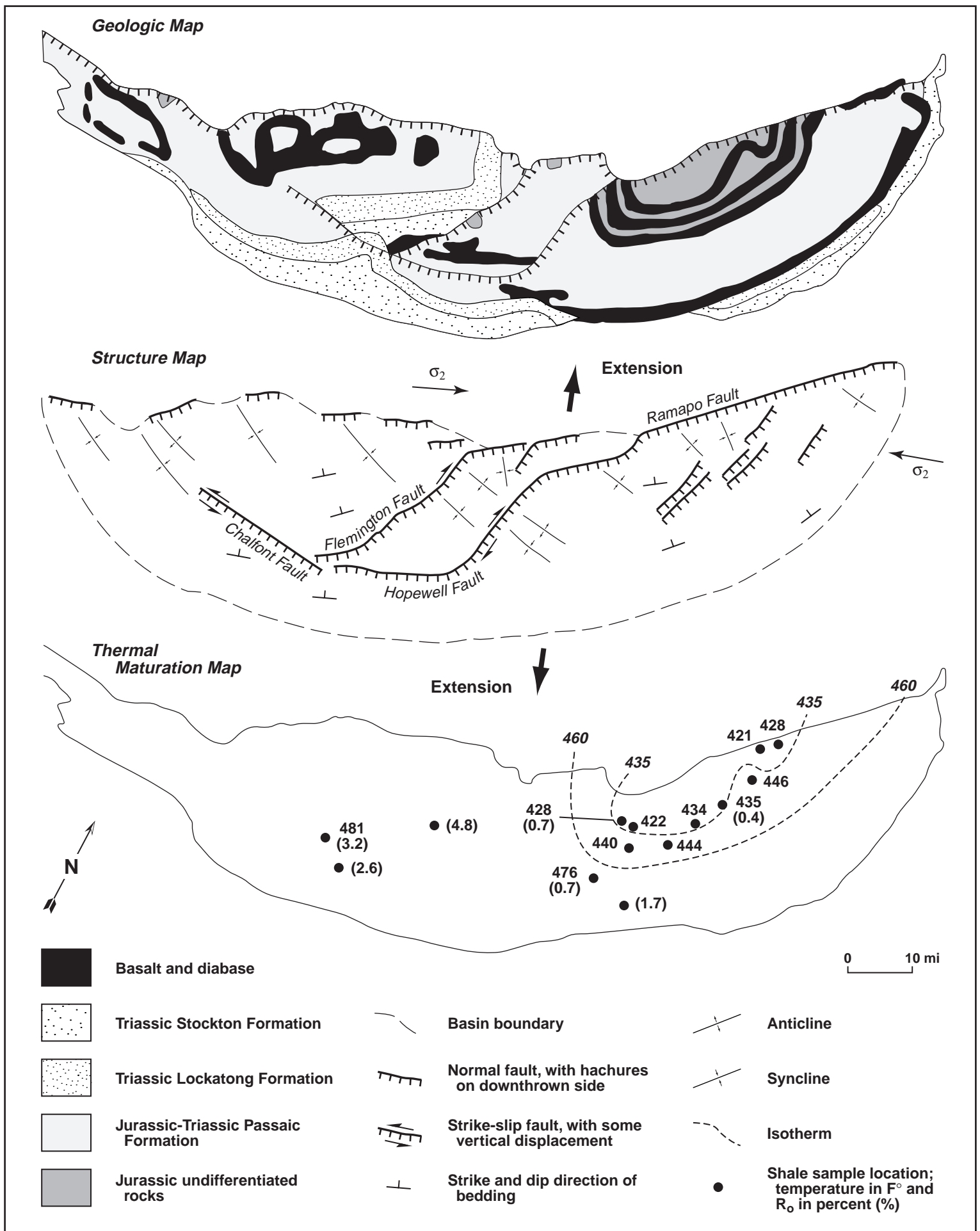


Figure 67. Maps of the Newark basin, showing geology, generalized structural features, direction of inferred extension and intermediate principal stress σ_2 , and maximum pyrolytic yield and mean vitrinite reflectance R_0 . After [Manspeizer \(1981\)](#), [Turner-Peterson and Smoot \(1985\)](#), [Pratt et al. \(1988\)](#), and [Schultz \(1988\)](#).

Series	Stage	Narrow Neck of the Newark basin, Pennsylvania		Newark basin, Pennsylvania		Newark basin, New Jersey-New York		
Lower Jurassic	Toarcian					Brunswick Group		Boonton Formation
	Pliensbachian							Hook Mountain Basalt
	Sinemurian							Towaco Formation
	Hettangian							Preakness Basalt
				Feltville Formation				
				Orange Mountain Basalt				
	Upper Triassic			Upper Norian	Hammer Creek Formation		Brunswick Group	upper part Brunswick Group
Middle Norian		Jacksonwald Basalt						
Lower Norian								
Upper Carnian		lower part Brunswick Group	Passaic Formation					
Middle Carnian		New Oxford Formation	Stockton Formation		Perkasie Member	Perkasie Member		
				Graters Member	Graters Member			
Lower Carnian				Lackatong Formation				
				Stockton Formation				

Figure 68. Stratigraphic columns for the Newark basin in Pennsylvania, New Jersey, and New York. After [Smoot et al. \(1988\)](#).

MICHIGAN BASIN (ST. PETER SANDSTONE)

GEOLOGIC SETTING

The Michigan Basin is a circular-shaped intracratonic basin covering about 80,000 square miles (Catacosinos and Daniels, 1991). Structural boundaries of the basin include the Canadian Shield on the north, the Algonquin Arch on the east, the Findlay Arch on the south and east, and the Kankakee and Wisconsin Arches on the south and west (Figure 69). The basin contains Paleozoic marine sediments overlying Precambrian basement (Figures 69 and 70).

The Middle Ordovician St. Peter Sandstone consists of massive sandstones interbedded with thinner dolomites (Figure 70). Deposition of this transgressive marine succession occurred in peritidal to storm-dominated outer-shelf environments (Catacosinos and Daniels, 1991). In the center of the Michigan Basin, the St. Peter conforms to and interfingers with the Trempealeau and Prairie du Chien Formations; however, at the basin margins, the sandstone lies unconformably over underlying units (Figure 70). Similarly, at the basin center the St. Peter grades to the overlying Glenwood Formation, but rests unconformably over underlying units at the basin margins. The St. Peter thickens to almost 1,100 ft in the basin center (Figure 71).

The quartzose sandstones of the St. Peter are fine- to medium-grained and cemented with silica and dolomite. Diagenesis has generally reduced porosities to less than 3%, but locally they may reach 10 to 15%. Porosity reduction occurred early in the burial history of the St. Peter (Drzewiecki et al., 1994). The formation contains several repetitive sequences that reflect the transgressive and highstand cycles resulting from major subsidence and structural movement within the basin. The sequences appear as wireline log signatures and corresponding lithologies (Figure 72) (Dott and Nadon, 1992). The repetition of sandstone, claystone, and dolomite has not only influenced the diagenetic banding of the sandstone reservoirs, but also has compartmentalized the reservoir pressures.

Sandstone permeability ranges from 1.0 to >100 md (Figure 73) (Bahr et al., 1994).

HYDROCARBON PRODUCTION

The St. Peter has historically had some exploration, but well penetration and testing occurred only in the usually tight upper part. Over 36 gas fields have been discovered in the Glenwood-St. Peter “Deep Play” since the late 1980s (Barnes et al., 1992). Production depths vary from about 5,000 to 11,500 ft. Falmouth field produced 5.1 BCF from 1987 to 1990, and some estimates place the per-well reserves at 2.0 to 14 BCF per 640 acre spacing.

Tests within the St. Peter Sandstone indicate overpressure exceeds 300 psi (Figure 73). Dott and Nadon (1992) believe overpressuring in the formation resulted from hydraulic head created during Wisconsin glaciation. Bahr et al. (1994) compared brine heads in the basin to ground surface elevations and found a large area of overpressures occurring within the St. Peter and Glenwood formations west and north of Saginaw Bay. Figure 71 shows the mapped area of overpressure in the St. Peter. Bahr’s results showed an apparent association of vertical variations in overpressures with vertical variations in permeabilities, which possibly indicates a stacked system of smaller compartments within a larger compartment. Figure 72 illustrates the repetitive depositional sequences within the St. Peter that could represent the smaller pressure compartments within the reservoir’s megacompartments.

Most traps are structural, and consist of several-mile long anticlines having closures of 20 to 80 ft west of a Precambrian rift and 100 to 200 ft east of the rift (Figure 71). Stratigraphic traps potentially exist, and fracture systems may also be present.

Organic-rich shales in the Ordovician Foster Formation probably source the St. Peter Sandstone.

EVIDENCE FOR BASIN-CENTERED GAS

Vitrinite reflectance data suggests the Michigan Basin Ordovician section is thermally mature ([Cercione and Pollack, 1991](#)); the authors noted that the present-day geothermal gradient and overburden depth could not account for the maturation and concluded that a steeper gradient with an overburden composed of fluvial-deltaic sediments would create a tighter seal to cook the organic material.

Although structure controls most gas production from the St. Peter, mapping the internal depositional and diagenetic sequences could identify stratigraphically controlled reserves ([Dott and Nadon, 1992](#); [Winter et al., 1995](#)). If a seal exists, the erosional limit of the St. Peter Sandstone may hold a regional stratigraphic pinch-out play.

KEY ACCUMULATION PARAMETERS

Identification

Michigan Basin, Ordovician, St. Peter Sandstone, overpressured.

Geologic Characterization of Accumulation:

- | | |
|---|---|
| a. Source/reservoir | The St. Peter Sandstone is probably sourced from organic-rich shales in the Ordovician Foster Fm. Production associated with anticlinal structures suggests the presence of fracture systems. Overpressuring is the result of the hydraulic head created during the last glacial event. |
| b. Total Organic Carbons (TOCs) | |
| c. Thermal maturity | Vitrinite reflectance values vary from .50 to 1.5 for the Ordovician (Cercione and Pollack, 1991). |
| d. Oil or gas prone | Gas prone. |
| e. Overall basin maturity | |
| f. Age and lithologies | Middle Ordovician sandstones, dolomites, and shales. |
| g. Rock extent/quality | Basin-wide source and reservoir-rock distribution. Currently 36 fields produce from the Glenwood-St. Peter "deep play" (Barnes et al, 1992). |
| h. Potential reservoirs | |
| i. Major traps/seals | Most production occurs in anticlinal features with 20 ft to 200 ft closures associated with structural deformation occurring along the Midcontinent Rift System. Potential exists for stratigraphic traps as well. |
| j. Petroleum generation/migration models | |
| k. Depth ranges | 1.5 km to 3.5 km (0.9 to 2.2 mi). |
| l. Pressure gradients | Pressures reported to be 300 psi in excess of expected formation pressures. |

Production and Drilling Characteristics:

- | | |
|---------------------------------------|---|
| a. Important fields/reservoirs | Falmouth field plus 35 other fields produce from the St. Peter Sandstone. |
|---------------------------------------|---|

b. Cumulative production Falmouth field has produced in excess of 5.1 bcf from 1987 to 1990.

**Economic
Characteristics:**

a. Inert gas content None

b. Recovery Good to moderate.

c. Pipeline infrastructure Good

**d. Exploration maturity
relative to other basins** Mature basin based on later Paleozoic exploration and production.

e. Sediment consolidation Good to moderate consolidation.

**f. Porosity/completion
problems** Low porosities and variable permeabilities may require stimulation of the reservoir.

g. Permeability 0.01 to 100 md

h. Porosity 3 to 10%

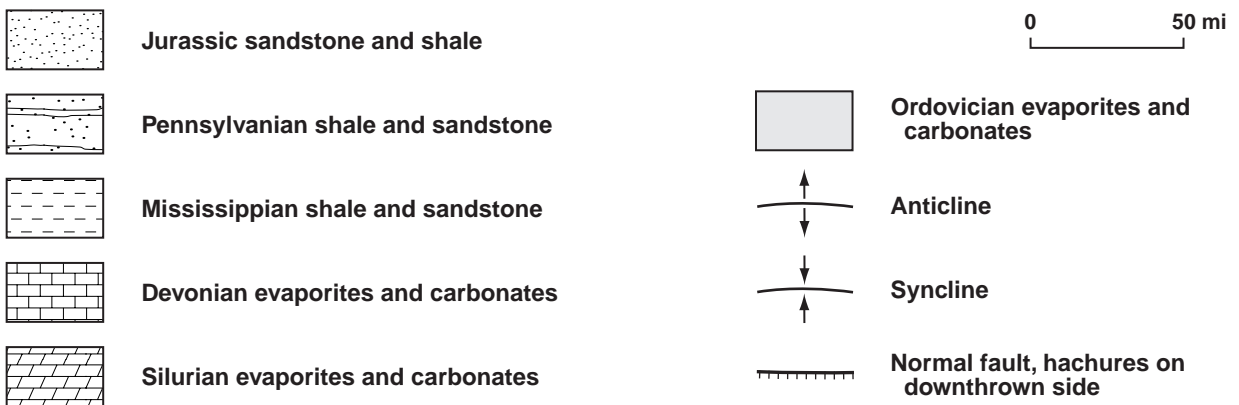
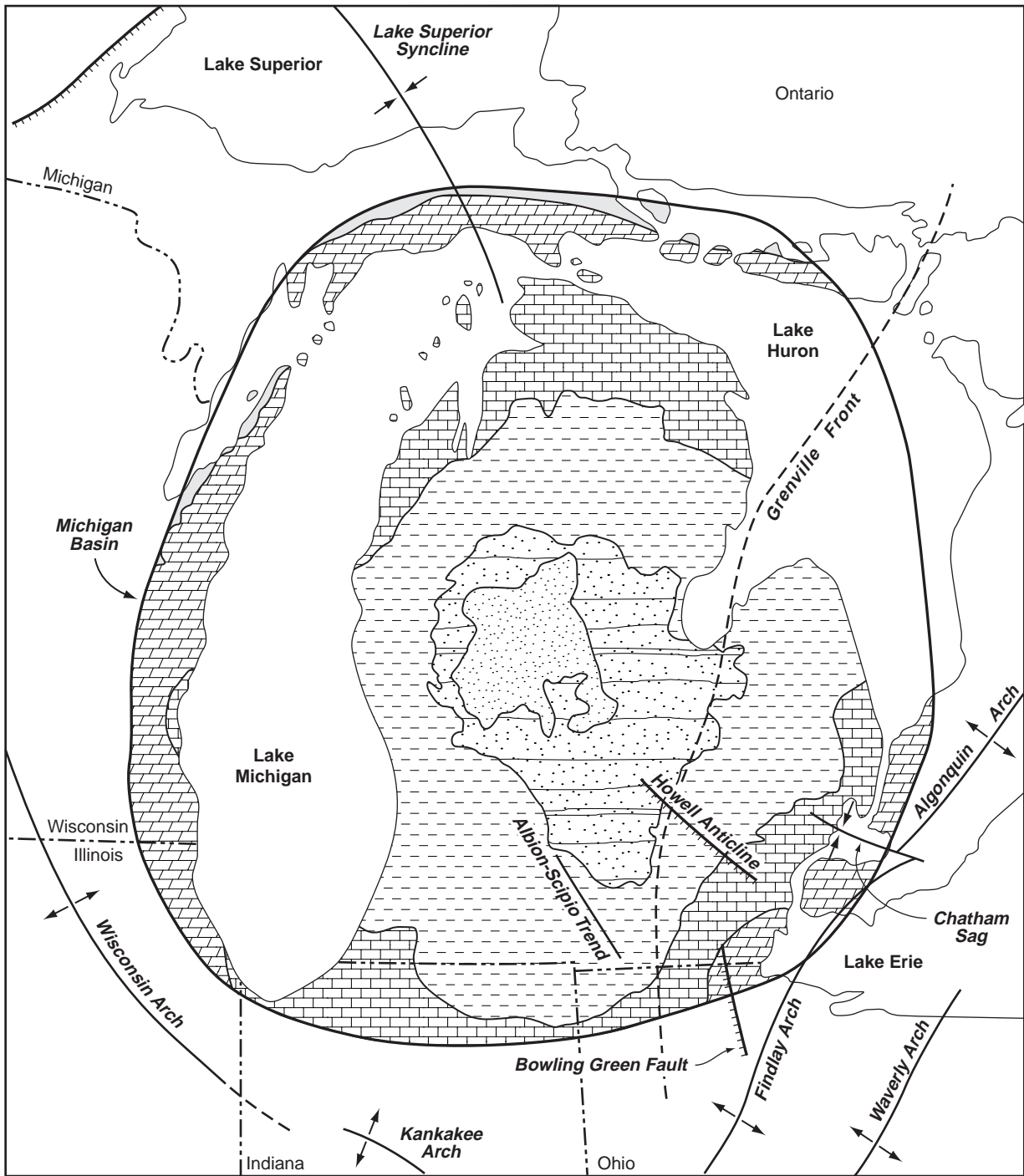


Figure 69. Geologic map of the Michigan Basin. After [Catacosinos and Daniels \(1991\)](#) and [Dott and Nadon \(1992\)](#).

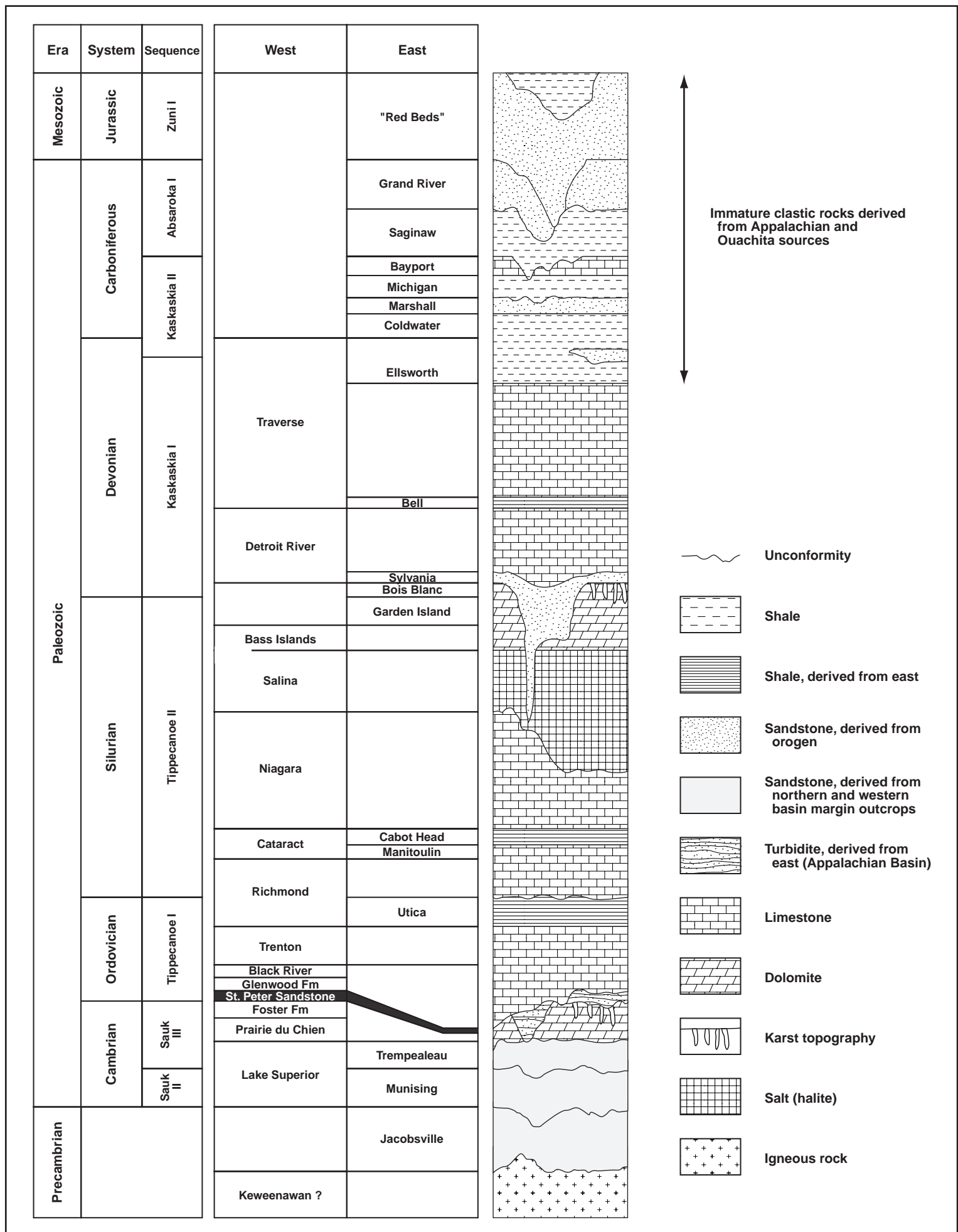


Figure 70. Stratigraphic column of the Michigan Basin. After [Catacosinos and Daniels \(1991\)](#), [Dott and Nadon \(1992\)](#).

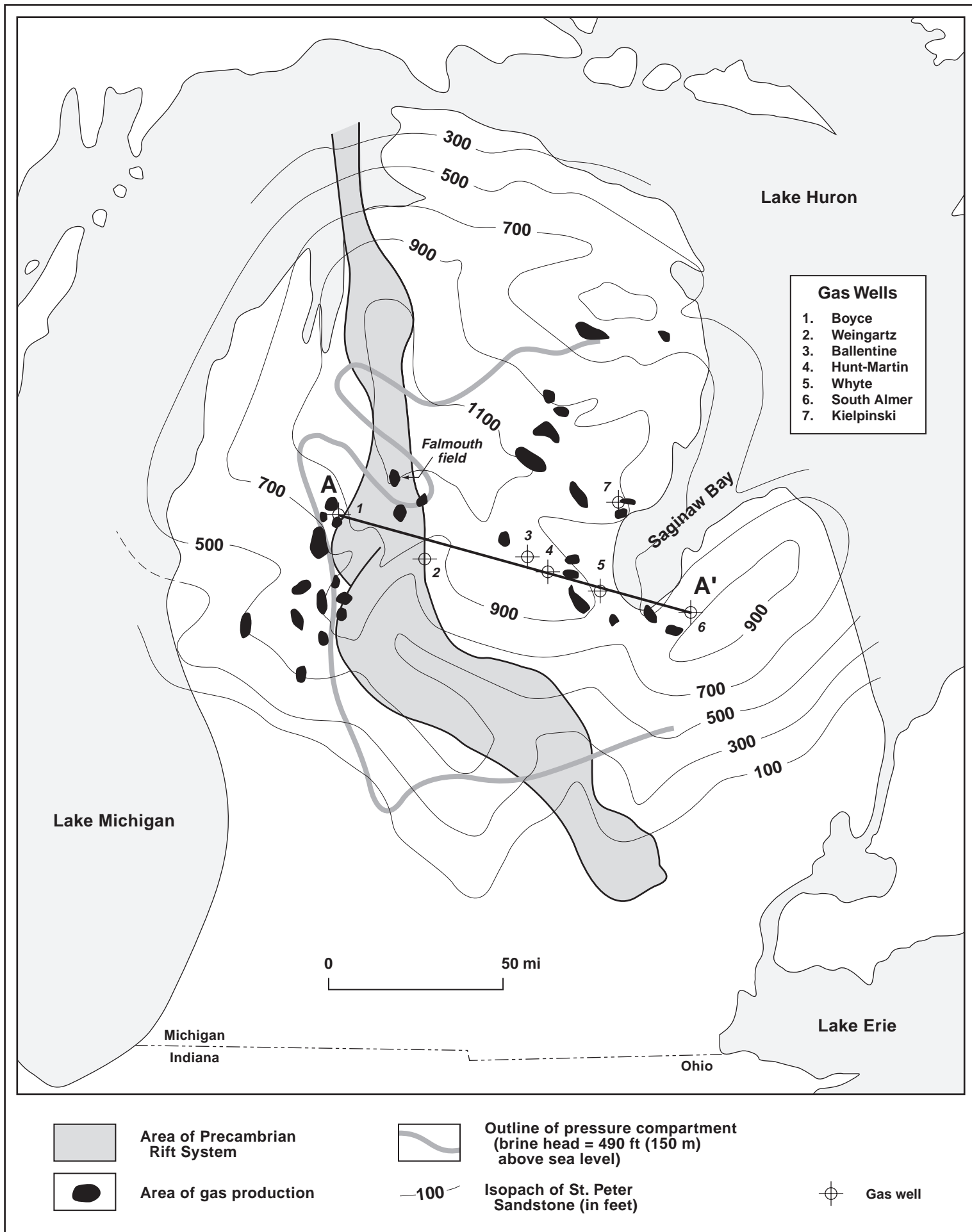


Figure 71. Isopach map of the St. Peter Sandstone overlain by a Precambrian rift system, gas production areas from the Glenwood Formation and St. Peter Sandstone, and pressure compartment outline. Cross section A-A' shown on [Figure 72](#). After [Catacosinos and Daniels \(1991\)](#) and [Bahr et al. \(1994\)](#).

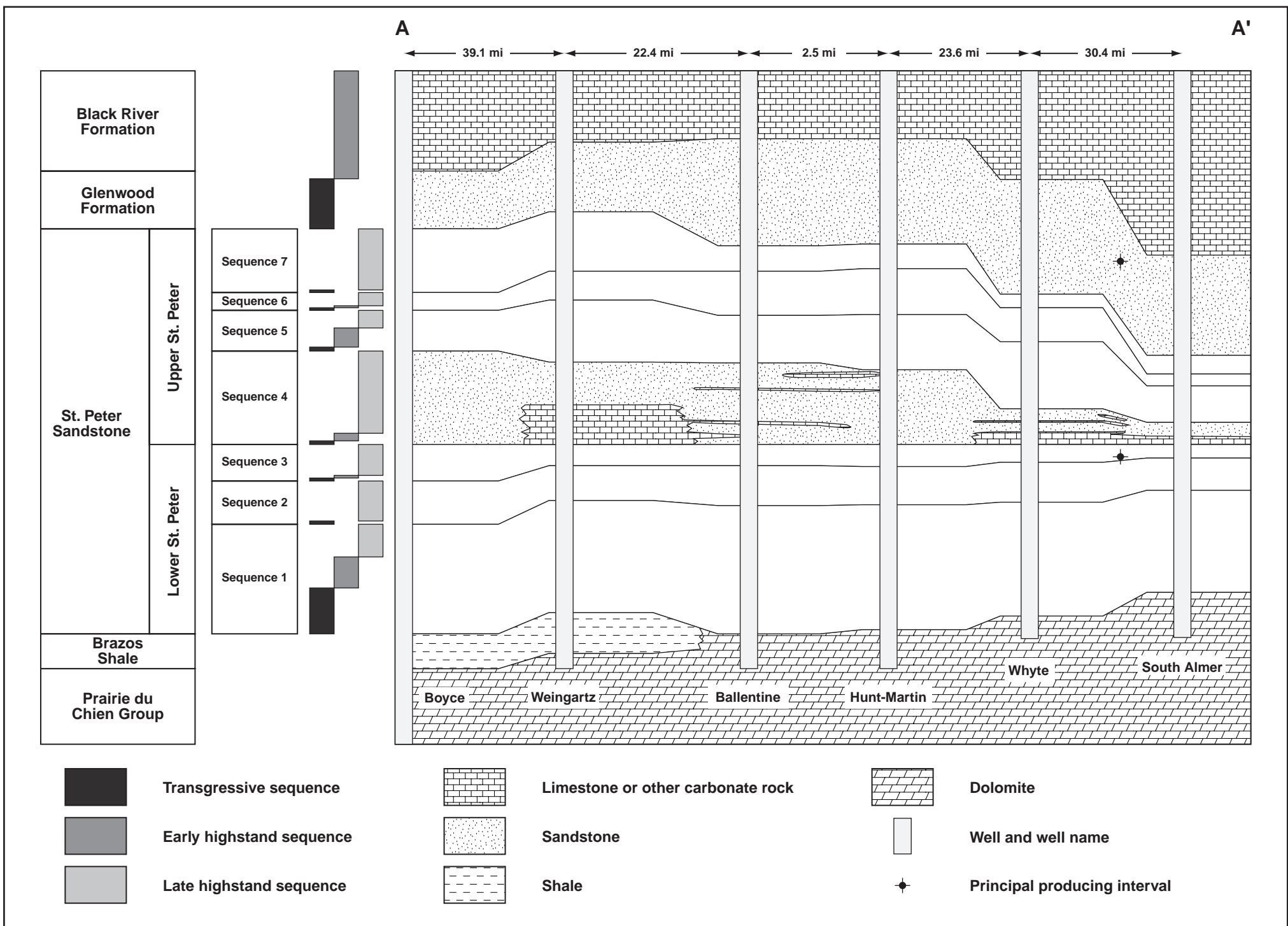
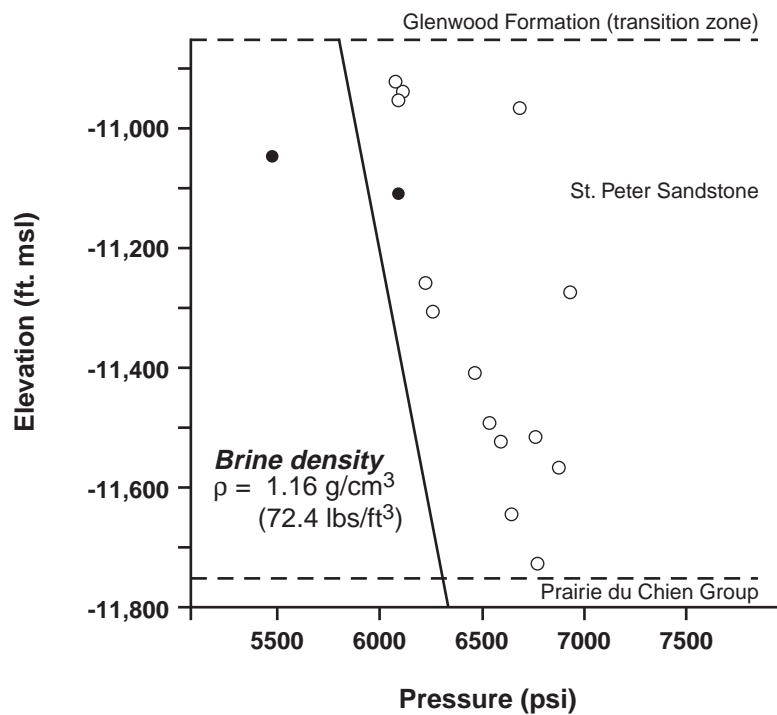
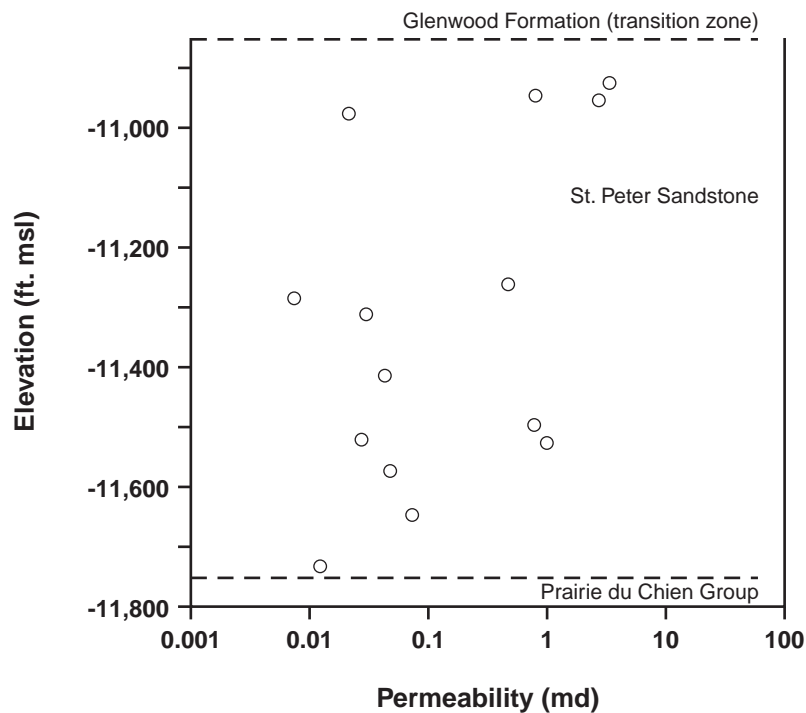


Figure 72. West-east cross section through central Michigan basin showing internal depositional, highstand and transgressive sequences within the St. Peter Sandstone and the Glenwood Formation. **Figure 71** shows the section location. After [Dott and Nadon \(1992\)](#).



- Data point from drill stem test
- Data point from repeat formation test

Figure 73. Permeability distribution and pressure variation within the St. Peter Sandstone, derived from drill stem tests and repeat formation tests in the Kielpinski well (see [Figure 71](#)), Bay County, Michigan. After [Bahr et al. \(1994\)](#).

MID-CONTINENT RIFT

GEOLOGIC SETTING

The Mid-Continent Rift is a 57,000 square mile horst and graben system located in the north-central U.S. It follows an 800-mile long north-northeasterly trend from south-central Kansas to northeastern Minnesota, northwestern Wisconsin, the western part of the Upper Peninsula of Michigan, and into central Michigan (Figure 74) (Palacas, 1995). Precambrian (Keweenawan) in age, this feature represents a failed continental rift characterized by broad horst blocks composed of layered basalts and flanked by high-angle normal faults that form the boundaries of adjacent sediment-filled half-grabens (Palacas, 1995). Development of the rift occurred approximately 1.1 billion years before present (Dickas, 1986). Dickas (1986) mapped the rift extent by recognizing significant gravity and magnetic anomalies throughout the trend. Newell et al. (1993) noted rejuvenation of some structural features by steeply dipping reverse faults, where the central horst has thrust over the basin margin.

Stratigraphy appears generally similar along the rift complex, based on outcrop descriptions and logs for wells that have penetrated rift sediments (Figure 75). Sedimentary rocks in the Mid-Continent rift include arkosic and feldspathic sandstones, conglomerates, siltstones, and micaceous red, green and gray shales deposited in marine (Scott, 1966), alluvial plain (Dickas, 1986), and alluvial fan and lacustrine environments (Daniels, 1982; White and Wright, 1960; Tryhorn and Ojakangas, 1972; Kalliokoski, 1982; Catacosinos, 1973; and Fowler and Kuenzi, 1978). Layered basalts are common within the rift and compose a central horst block.

The Defiance basin in Iowa is one of the deepest in the rift system. Geophysical modeling indicates 32,800 ft of sediments (Anderson and Black, 1982). An exploratory well drilled in Iowa penetrated 1,355 ft of Keweenawan clastics, 55% of which were red-brown shales (Dickas, 1986). Two other exploratory wells penetrated significant thicknesses of Mid-Continent rift strata (Figure 74): the Texaco No. 1 Poersch (11,301 ft total depth/8,455 ft of rift strata penetrated) in northeastern Kansas; and the Amoco No. 1 Eischeid (17,851 ft total depth/14,898 ft of rift strata penetrated) in west-central Iowa (Newell et al., 1993). Five wells have penetrated the Precambrian Nonesuch Shale and equivalents within the rift.

Major traps or seals include interbedded shales, siltstones, layered basalts, and fault gouge within the Nonesuch Formation, and tight horizons in the overlying Freda Sandstone and Bayfield Group (Figure 75).

HYDROCARBON PRODUCTION

There is no significant hydrocarbon production within the rift. In 1933, operators produced small amounts of oil from fractured Precambrian quartzites in central Kansas, at the southern end of the rift trend. Paleozoic source rocks probably expelled this oil, which then migrated laterally into the Precambrian rocks along structural highs (Walters, 1953).

EVIDENCE FOR BASIN-CENTERED GAS

The Texaco No. 1-31 Poersch encountered several shows of oil and gas during drilling and testing (Paul et al., 1985). Total organic carbon (TOC) values from the Amoco No. 1 Eischeid in Iowa ranged up to 1.4%, but the section is overmature (average $T_{max} = 503^{\circ}\text{C}$). In southeastern Minnesota, the Lonsdale No. 65-1 well encountered dark gray mudstone of the Solor Church (Nonesuch) Formation, and TOC values varied from 0.13% to 1.77% (Palacas, 1995); the average T_{max} was 494°C (Hatch and Morey, 1984; 1985). In 1929, a cable-tool rig drilled 822 ft of Precambrian carbonaceous shales and sandstones and had some oil and gas shows (Newell et al., 1988). This well was 21 miles northeast of the Texaco No. 1 Poersch well.

The Precambrian Nonesuch Fm and equivalents evidently have hydrocarbon generative potential throughout the rift system. The interval contains 250 to 700 ft of interbedded, laminated, dark gray to black siltstone, silty shale and sandstone. The silty shale contains TOC values averaging 0.6% and reaching a maximum of 3% (Imbus et al., 1990; Pratt et al., 1991). The greatest TOC values in the Nonesuch and equivalents occur near the middle of the unit and toward the eastern end of the rift system in northern Michigan.

Palacas (1995) reported that the Nonesuch generated oil and gas from type I and type II kerogens in the deeper parts of several of the rift basins. Thermal maturity was sufficient to crack oils into gaseous hydrocarbons in the Iowa and Minnesota segments of the rift. He concluded that two phases of hydrocarbon generation occurred, one during the early phase of rift extension, and the second during a compressional phase after the deposition of Paleozoic sediments. Remigration of hydrocarbons probably occurred during the second stage.

Newell et al. (1993) measured a present day geothermal gradient of 15.6°F per 1,000 ft in the 1-4 Finn well in northeastern Kansas (Figure 76); the bottom-hole temperature at 3,974 ft was 116°F . Thus, bottom-hole temperatures in deeply buried rift sediments should have sufficed for hydrocarbon generation. No pressure data is known to exist for wells drilled into the Nonesuch or equivalent rocks (K.D. Newell, Kansas Geological Survey, 1999, personal communication).

KEY ACCUMULATION PARAMETERS

Identification

Superior Province, Mid-Continent rift, potential basin-centered gas play.

Geologic Characterization of Accumulation:

- | | |
|---|--|
| a. Source/reservoir | Oronto Group (Wisconsin), Nonesuch Formation (Michigan and Wisconsin), Solor Church Formation (Minnesota), Lower Red Clastics (Iowa), Red Clastics (Nebraska), and Rice formation (Kansas). |
| b. Total Organic Carbons (TOCs) | Range from 0 to 3% |
| c. Thermal maturity | Tmax 423 – 503° C |
| d. Oil or gas prone | Oil prone; mostly type I and II kerogen. |
| e. Overall basin maturity | Maturation levels are moderate to high. Highest thermal maturity is in Iowa and Minnesota and with depth and proximity to central horst. R _o ranges from 0.5 to 1.43 %. |
| f. Age and lithologies | Precambrian (Keweenaw) age, Nonesuch (and equivalent) arkosic sands, silts and silty shales |
| g. Rock extent/quality | Wide source and reservoir rock distribution. Reservoir quality is unknown because of few outcrops and few wells drilled. Expected reservoir quality varies depending on clay content, interbedded shales and silts and the degree of fracturing. |
| h. Potential reservoirs | No production. Precambrian Nonesuch and equivalents. |
| i. Major traps/seals | Interbedded shales, siltstones, layered basalts and fault gouge within the Nonesuch formation, tight horizons have also been identified in the overlying Freda sandstone and in the Bayfield group. |
| j. Petroleum generation/migration models | In-situ generation and short distance migration. Hydrocarbon generation may be ongoing in deeper basins. Present day geothermal gradient is 15.6° F per 1000 ft. The Bakken shale model of Meissner (1978) may apply in the rift for hydrocarbon generation and expulsion directly into adjacent beds. |
| k. Depth ranges | Accumulation depths are thought to range from 3000 ft to 25,000 ft. |
| l. Pressure gradients | |

**Production and Drilling
Characteristics:**

- | | |
|---------------------------------------|--|
| a. Important fields/reservoirs | Entire rift trend virtually untested; no production to date. |
| b. Cumulative production | None |

**Economic
Characteristics:**

- | | |
|---|--|
| a. Inert gas content | Unknown |
| b. Recovery | Recoveries would vary depending on permeability, porosity and depth; diagenetic alteration may increase with depth. |
| c. Pipeline infrastructure | Poor |
| d. Exploration maturity relative to other basins | Immature |
| e. Sediment consolidation | Most rocks are well indurated. |
| f. Porosity/completion problems | Silty shales, clay, and arcose/feldspathic sands have high alteration potential; also may have swelling clays and will produce migrating fines problems. Silty shales and siltstones are interbedded with sands. |
| g. Permeability | |
| h. Porosity | Average porosities range from 4% to 18%. |

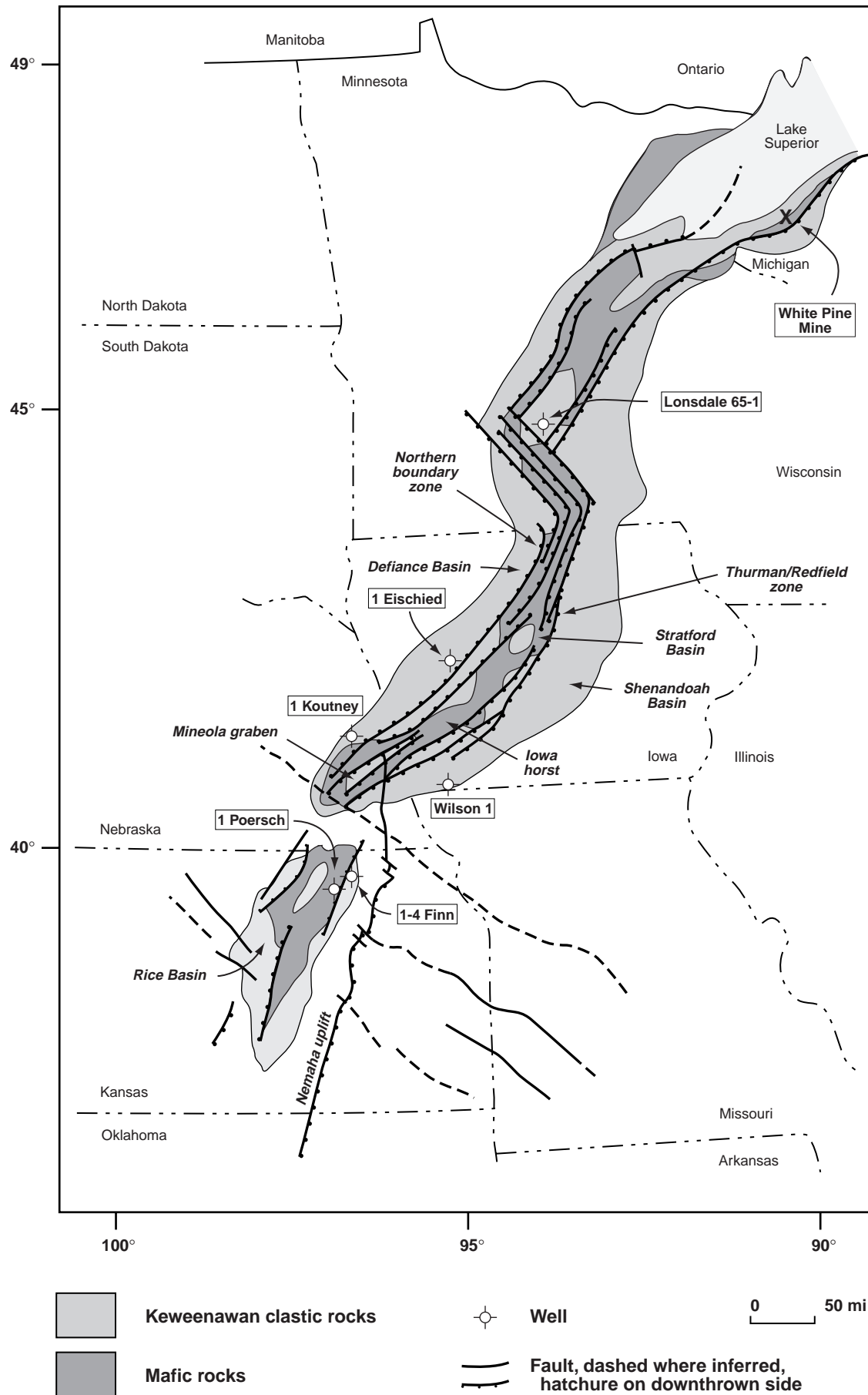
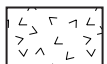


Figure 74. Location map of the Mid-Continent rift system in the central United States. After Dickas (1986) and Newell et al. (1993).

Era	Series	Kansas	Nebraska	Iowa		Minnesota		Wisconsin		Michigan Upper Peninsula			
				horst	flank	horst	flank	horst	flank				
Proterozoic	Upper Keweenawan	Rice Formation	"red clastics"		* "upper red clastic sequence"				Bayfield Group	Chequamegon Sandstone	Jacobsville Sandstone		
						Hinkley Sandstone				Devils Island Sandstone			
							Fond du Lac Formation			Orienta Sandstone			
				* "lower red clastic sequence"		Solor Church Formation		Oronto Group		Freda Sandstone			
										Nonesuch Shale			
										Copper Harbor Conglomerate			
				Middle Keweenawan						Chengwatana Volcanic Group		Portage Lake Volcanics	



Volcanic rocks

* Tentative correlations (per Newell et al, 1993)

Figure 75. Stratigraphic correlation of units along the Mid-Continent rift system, central United States. After Dickas (1986) and Newell et al (1993).

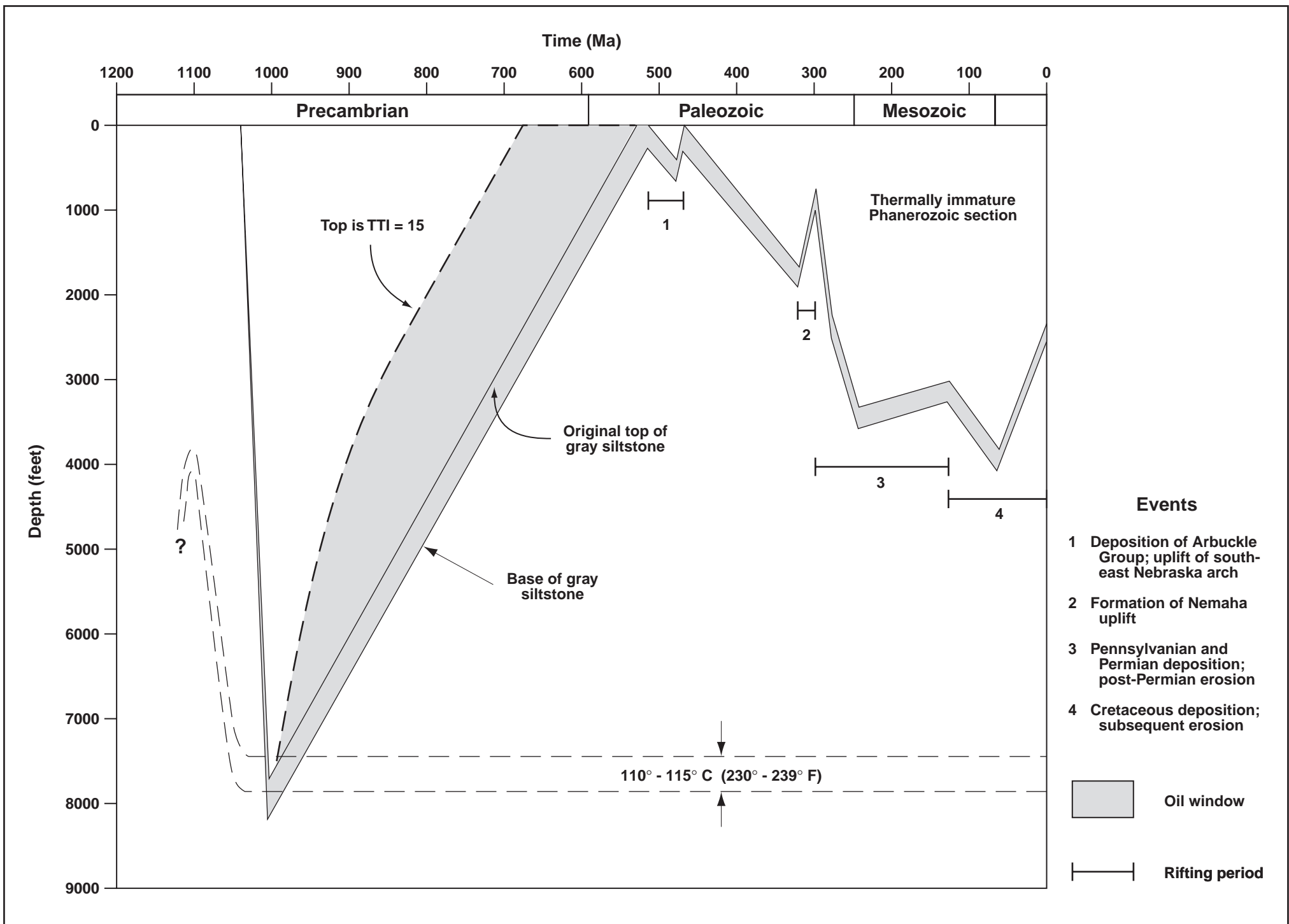


Figure 76. Time-temperature index (TTI) model of the 1-4 Finn well (see Figure 74). The graph depicts a 40° C/km (2.19° F/100 ft.) geothermal gradient following a heat pulse during rifting. The relationship of subsidence and thermal decline during rifting is speculative. After Newell et al. (1993).

PARADOX BASIN (CANE CREEK INTERVAL)

GEOLOGIC SETTING

The Paradox Basin extends across southeastern Utah and southwestern Colorado along a roughly northwest-southeast trend. Several structures form its boundaries and contributed sediments: the ancestral Uncompahgre Uplift to the northeast, the Monument Uplift to the southwest, and the Emery Uplift to the northwest ([Figure 77](#)) ([Baars and Stevenson, 1981](#)). [Figure 78](#) shows a partial stratigraphy of the basin.

During the Pennsylvanian (Desmoinesian) period, the basin accumulated deposits of algal carbonates and evaporites (halite, gypsum, and potash) which interfingered with clastic deposits shed from surrounding higher regions (mostly the ancestral Uncompahgre Uplift; the present Uncompahgre Plateau formed during the early Tertiary Laramide orogeny). Toward the basin depocenter, evaporite deposits interfinger with siltstones, organic-rich dolomites and black shales. Deposition of Uncompahgre alluvium deformed the underlying salts, which created northwest- to southeast-trending anticlines parallel to basement faults ([Figure 79](#)) ([Hite and Buckner, 1981](#)).

The Cane Creek interval is the 22nd of 29 carbonate cycles identified within the Paradox Member of the Hermosa Formation ([Figures 78 and 80](#)) ([Hite et al., 1984](#)). Three units make up the Cane Creek interval: the uppermost "A" unit of interbedded red siltstone and anhydrite; the "B" unit of black, organic-rich shales and dolomites; and the lowermost "C" unit of interbedded red siltstone and anhydrite. The "B" unit represents the source and reservoir rock and varies in thickness from less than 10 ft to almost 30 ft. Combined, the three clastic units are almost 150 ft thick near the basin depocenter, but pinch out against the ancestral Uncompahgre flank ([Morgan, 1992](#)). The interval thins in synclines and thickens on anticlines; this occurrence may result from (1) original deposition associated with fault movement, (2) structural thickening from small-scale folding and faulting (i.e., repeat sections), and/or (3) flowage within anhydrite layers ([Montgomery, 1992](#)).

HYDROCARBON PRODUCTION:

Most production in the Paradox originates from Ismay and Desert Creek carbonates in the southern part of the basin. Some structures in the Mississippian Redwall and Leadville limestones also produce hydrocarbons. To date, Cane Creek production has occurred only in the northern part of the basin, and mostly from fractures and fracture intersections on the flanks of anticlines that parallel the ancestral Uncompahgre Uplift. The nature of the fracturing makes production very sensitive to drilling mud weights and completion techniques ([Montgomery, 1992](#)). As a result, recoveries vary greatly.

Cane Creek wells show significant reservoir overpressuring, at least 6,000 to 6,500 psi at depths of 7,200 to 7,500 ft. The overpressuring may result from salt flowage ([Montgomery, 1992](#)). Oil is typically sweet, having API gravities from 43 to 46. Gas associated with oil production is usually flared, because of the lack of pipelines in the area. The gas is sweet, containing between 1 and 2% nitrogen and/or carbon dioxide.

The # 1 Long Canyon well (9-26S-20E) drilled by Southern Natural Gas has yielded over 1 MBO since 1962. In 1991, Columbia Gas completed Kane Spring Federal No. 27-1 (27-15S-19E) in the Cane Creek interval using horizontal drilling; cumulative production to 1992 exceeded 100,000 bbls of oil.

EVIDENCE FOR BASIN CENTERED-GAS

The Cane Creek interval is rich in organic content and thermally mature. Data from the Gibson Dome well (Figures 79 and 80) shows total organic carbon (TOC) content in the interval to be 3.96 wt%; vitrinite reflectance (Ro) averaged 0.54, and Tmax reached 438° C (Hite et al., 1984). This data indicates the Cane Creek is self-sourced (C.W. Spencer, U.S. Geological Survey, 2000, personal communication). The reservoir/source may communicate with other organic-rich reservoir/ source rocks.

Traps within the Cane Creek interval appear to be small tightly folded salt structures; stratigraphic traps are possible. If the salt layers formed impermeable seals, significant overpressures would occur.

Temperatures in Columbia Gas wells in the Kane Spring and Shafer Canyon areas range from 114 to 132° C and probably indicate too low a reservoir temperature exists for a basin center accumulation to occur (M.S. Wilson, 2000, consulting geologist, written communication). However, at greater depth, reservoir temperatures and thermal maturity would probably be higher, and consequently, a basin center gas accumulation may be present in the deeper parts of the Paradox Basin.

KEY ACCUMULATION PARAMETERS

Identification

Rocky Mountain, Paradox Basin, Pennsylvanian, Hermosa Formation, Paradox Member, Cane Creek interval, overpressured.

Geologic Characterization of Accumulation:

- | | |
|---|---|
| a. Source/reservoir | The Cane Creek interval is self-sourcing, and current production indicates fracturing of the reservoir is required to produce economic quantities of oil and gas. Overpressuring largely occurs from salt deformation which may result from salt flowage in conjunction with reactivated basement structures. |
| b. Total Organic Carbons (TOCs) | Cane Creek interval in the Gibson Dome #1 core hole = 3.96 wt%. |
| c. Thermal maturity | Cane Creek interval in the Gibson Dome #1 core hole $R_o = 0.54$; $T_{max} = 438^{\circ} \text{C}$. |
| d. Oil or gas prone | Both oil and gas prone. |
| e. Overall basin maturity | The southern portion of the basin is immature. |
| f. Age and lithologies | Pennsylvanian black shales and dolomites. |
| g. Rock extent/quality | Source and reservoir rocks are distributed throughout the basin (although substantially less than the halite deposition limit typically used to define the limits of the Paradox Basin). About 486 wells (basin-wide) may have penetrated this interval. |
| h. Potential reservoirs | Cane Creek interval is sporadically productive and other organic-rich intervals, such as the Chimney Rock and Gothic intervals (Figure 78) along with many other unnamed units may deserve closer attention. |
| i. Major traps/seals | May be discrete tightly folded salt structures associated with basement fault blocks. Possible stratigraphic traps may result from lateral facies changes to continentally derived red-beds. |
| j. Petroleum generation/migration models | |
| k. Depth ranges | 2000 ft; on some structures to 7500 ft |
| l. Pressure gradients | Average formation pressure is highly pressured (approximately 0.85 psi/ft) (Montgomery, 1992). |

**Production and Drilling
Characteristics:**

- | | |
|---------------------------------------|---|
| a. Important fields/reservoirs | Bartlett Flat, Cane Creek, Gold Bar, Long Canyon, Shafer Canyon, Wilson Canyon. |
| b. Cumulative production | The Long Canyon well has produced in excess of 1 MMBO since 1962, and the Kane Creek Federal #27-1 has produced in excess of 100 MBO as of 1992 (Montgomery, 1992). |

**Economic
Characteristics:**

- | | |
|---|--|
| a. Inert gas content | No; from 1.0 % to 3.0 %. |
| b. Recovery | Highly variable |
| c. Pipeline infrastructure | Poor |
| d. Exploration maturity relative to other basins | |
| e. Sediment consolidation | The producing interval is well indurated due to depth of burial. |
| f. Porosity/completion problems | The reservoir/source rock is fractured and overpressured; as a consequence, heavy weight drilling muds are often used, which may result in formation damage and difficult and costly completions. Production of hypersaline formation waters has often caused plugging of production tubing and equipment which may in turn give erroneous flow rates and production declines. |
| g. Permeability | Highly variable, fracture permeability. |
| h. Porosity | |

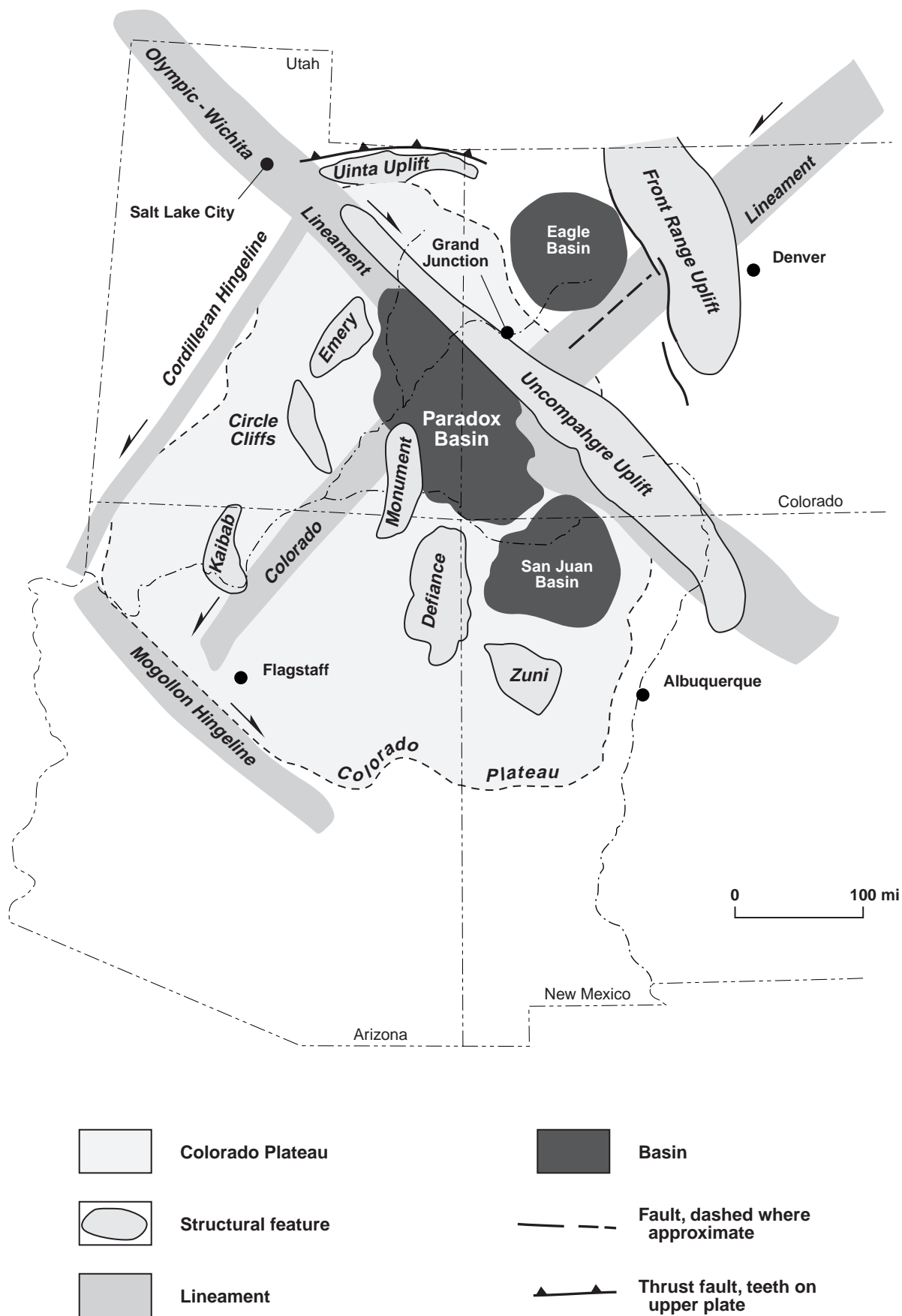


Figure 77. Location map of Paradox basin, showing the Colorado Plateau, other local basins, and structural features. After Baars and Stevenson (1981).

System	Series	Formation	Member	Evaporite Facies Cycle	Production Interval
Pennsylvanian	Virgilian	Hermosa	Upper (Honaker Trail)		
	Missourian				
	Desmoinesian		Paradox	1	Ismay
				2	
				3	
				4	Desert Creek
				5	
				6	Akah
				7	
				8	
				9	
				10	Barker Creek
				11	
				12 - 13	
				14	
				15	
				16	
				17	
				18	
				19	
				20	
				21	
				22	Alkali Gulch
				23	
				24	
				25	
				26	
				27	
				28	
				29	
	?		Lower (Pinkerton Trail)		
	Atokan				
	?	Molas			
	Morrowan				

← "Gothic"

← "Chimney Rock"

← "Cane Creek"

← "Gothic"

← "Chimney Rock"

← "Cane Creek"

Figure 78. Stratigraphic column for Pennsylvanian rocks in the Paradox basin. After [Hite et al. \(1984\)](#).

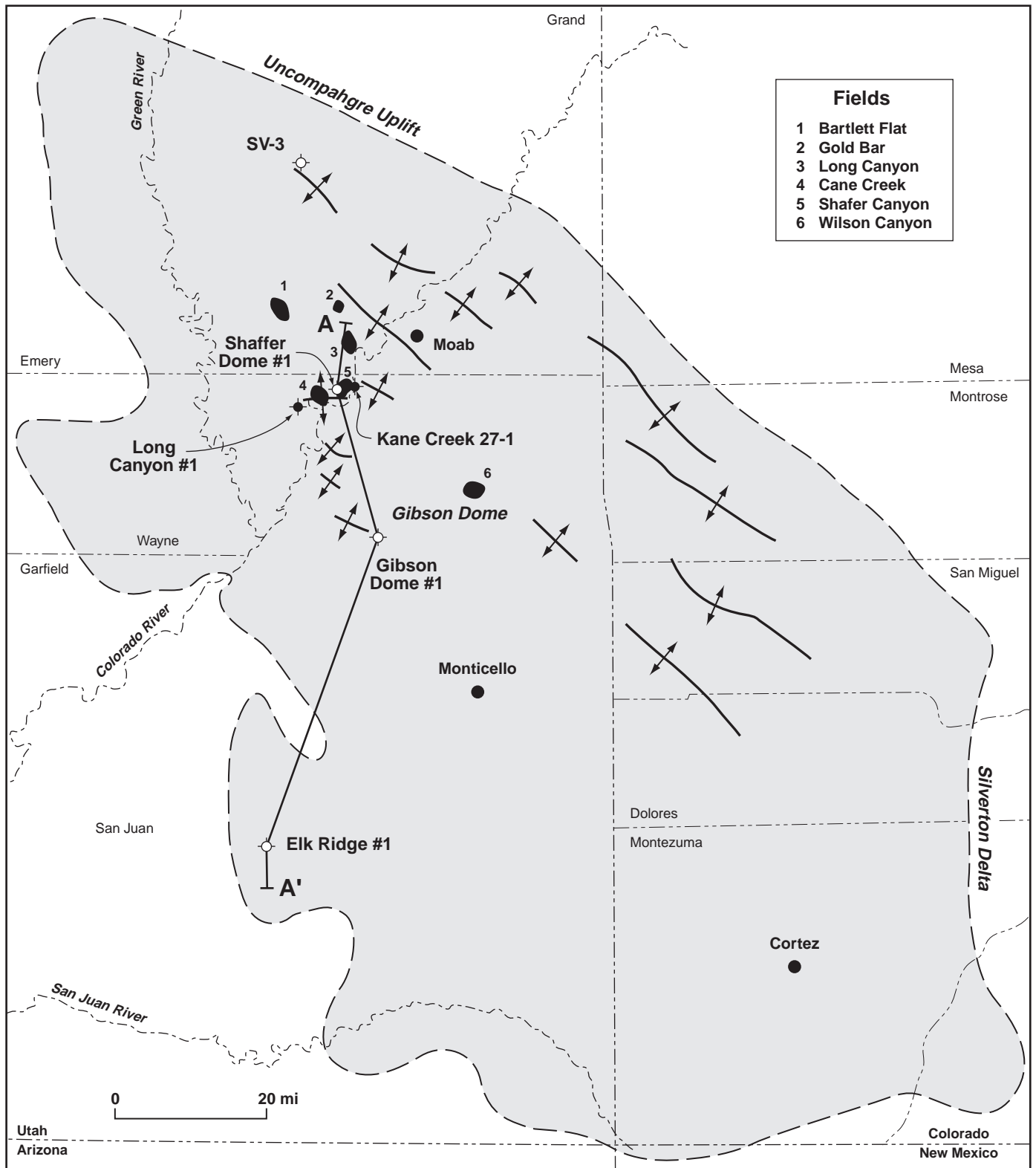


Figure 79. Map of the Paradox basin showing locations of core holes, wells, oil fields, cross section A-A' (shown in [Figure 80](#)), and basin boundary as defined by the limit of halite occurrence in the Paradox Member. After [Hite et al. \(1984\)](#).

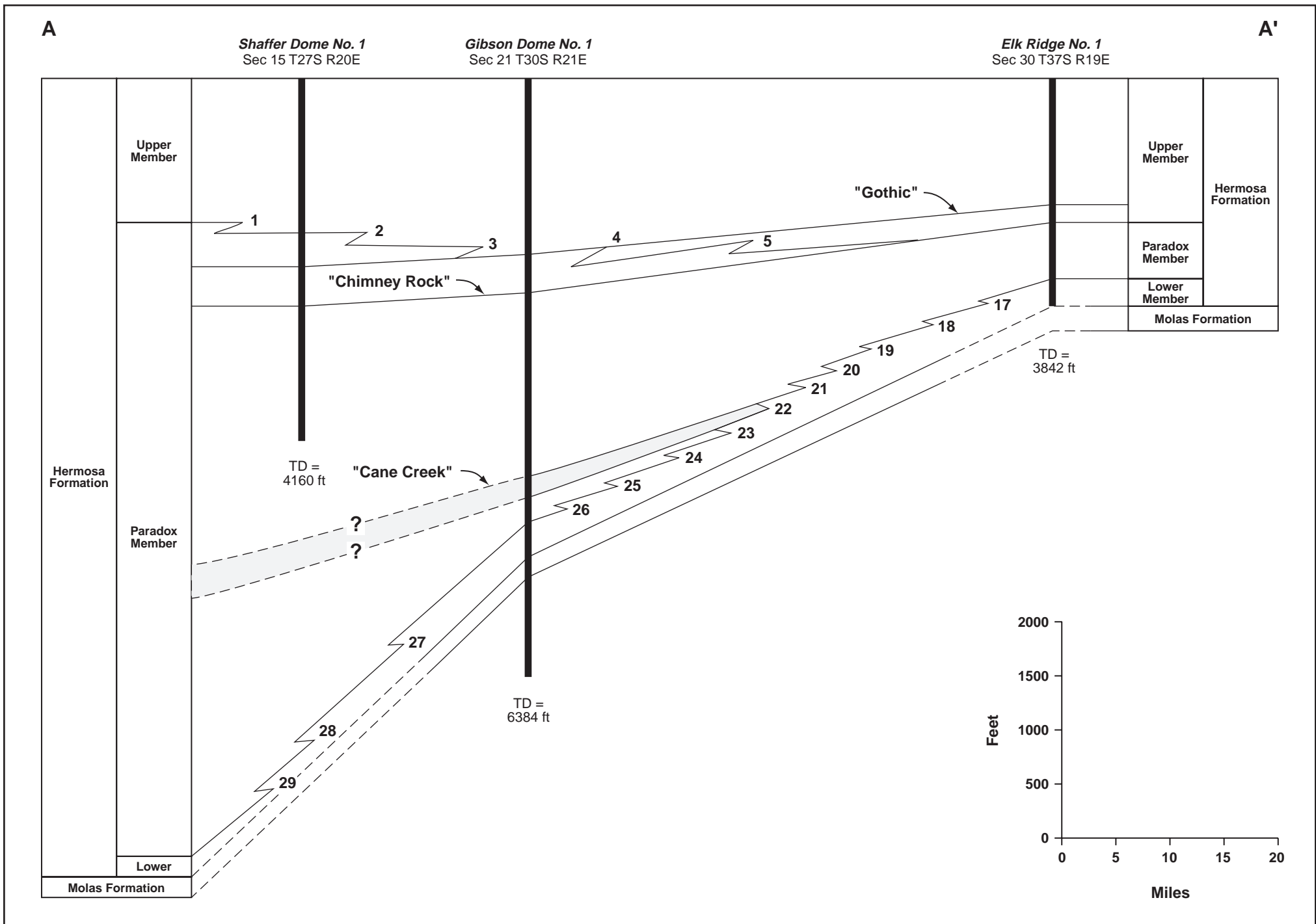


Figure 80. Diagrammatic north-south cross section A-A' showing Pennsylvanian rocks and carbonate cycles in three U. S. Department of Energy (DOE) core holes (SD-1, GD-1, and ER-1). Only the GD-1 core hole penetrated the Cane Creek interval. **Figure 79** shows location of the cross section. After [Hite et al \(1984\)](#).

PARK BASINS OF COLORADO

GEOLOGIC SETTING

The Park Basins are located 50 miles west of Denver, in central Colorado. Four mountain regions define the basin limits: the Front Range to the east; Medicine Bow Mountains to the north; Park, Gore, and Mosquito Ranges on the west; and the Thirty-nine Mile Volcanic Range to the south ([Figure 81](#)). Structural or stratigraphic differences separate the Park Basin into three intermontane basins—North, Middle, and South Park. Tertiary volcanics of the Rabbit Ears Range physically divide the otherwise structurally similar North and Middle Parks. Thirty miles to the south lies South Park Basin, which has undergone a more complex structural and stratigraphic history. Precambrian rocks and Tertiary intrusives of the Williams Fork and Vazquez Mountains isolate this basin from North and Middle Parks.

The 50-by 180-mile Park Basin complex is predominantly a north-south trending, asymmetrical syncline. The complex was an uplifted feature of the ancestral Front Range throughout most of the Paleozoic. The narrow syncline formed during the Late Cretaceous to Early Tertiary Laramide orogeny. Tectonism progressed from Late Cretaceous thrust faulting and folding to later episodes of intrusion, volcanism, and reverse and normal faulting. Major thrusts occur along the northern and eastern margins of the basin and show as much as 20 miles of movement ([Maughan, 1988](#)). Superimposed within the syncline are high-angle reverse faults (up to 10,000 ft of displacement), normal faults, tight folds, and volcanic rocks ([Figure 81](#)).

The basins preserve from 10,000 to 20,000 ft of sediments (sometimes stacked in thrust plates) ([Savant Resources LLC Report, 1999](#)). [Figure 82](#) shows stratigraphic columns for each park basin. Sediments of North and Middle Park Basins are largely Mesozoic sands, shales, and marls ([Figure 83](#)). Southwestern South Park exhibits a thick Paleozoic sequence of carbonates, shales, and arkosic sandstones ([Figure 84](#)). The Laramide orogeny caused a period of basin-wide non-deposition, so Tertiary sediments unconformably overlie Cretaceous rocks. The Tertiary section generally consists of non-marine clastics interspersed with coals and volcanics. Quaternary alluvium reflects the present quiescent phase of the basin.

HYDROCARBON PRODUCTION

Exploration has found hydrocarbons in anticlinal folds associated with thrusting in the Upper Jurassic-Lower Cretaceous shoreline sands of the North Park Basin ([Figure 83](#)). The [Colorado Oil and Gas Conservation Commission \(1997\)](#) recorded a total of 16.5 MMBO and 12.3 BCF from Battleship, Lone Pine, and North and South McCallum fields.

Target basin-centered gas intervals are in the Upper Cretaceous: the Apache Creek Sandstone of the Pierre Shale and the brittle, calcareous shales of the Niobrara ([Figure 82](#)). There are numerous hydrocarbon shows but no recorded production from the Apache Creek. The Pierre B sand is probably a sandstone equivalent to the Apache Creek and has produced approximately 1.4 MMCFG and 10.5 MBO ([Maughan 1988](#)). Fractured shales of the Niobrara Formation have produced about 278,000 BO and 156 MMCFG from the Delaney Butte, Michigan River, Canadian River, Coalmont, Johnny Moore Mountain, and Carlstrom fields ([Colorado Oil and Gas Conservation Commission, 1997](#)). [Mallory \(1977\)](#) provides details of this fracture play.

EVIDENCE FOR BASIN-CENTERED GAS

The Apache Creek Formation in South Park has had significant hydrocarbon shows. In 1999 [Savant Resources LLC](#) evaluated the basin and obtained gas data for the Hunt Tarryall Federal 1-17 well ([Figure 84](#)). The company found a 24-ft section of the Apache Creek yielded 195 MCFD of pipeline-quality gas. Testing revealed 0.3 md matrix permeability, 8.3% average porosity, and 0.52 psi/ft pressure gradient, which indicated formation damage. Savant recalculated open flow for the entire section and found 1,500 to 2,945 MCFD without hydraulic fracturing and 7,344 MCFD with induced fracturing.

The Federal 1-17 well data demonstrates [Spencer's \(1987\)](#) and [Surdham's \(1995\)](#) characteristics for accumulation of basin-centered gas:

1. *Overpressuring of the formation occurs below 10,000 ft.* The Apache Creek Sandstone at 11,150 feet displayed a pressure gradient of 0.52 psi/ft.
2. *Dry hydrocarbons are the fluid-pressuring phase and rarely produce water.* The pressure test recovered dry gas of pipeline grade (1021 Btu).
3. *Temperature of the overpressured rock is 180-230° F or greater.* The temperature of the Apache Creek Sandstone was 230° F.
4. *Source beds can generate hydrocarbons at rates exceeding loss. Minimum vitrinite reflectance (Ro) is 0.6% in oil-producing source beds and greater than 0.7% in gas-producing source beds.* Pierre and Upper Niobrara shales exhibit Ro values between 1.3 and 1.4% Ro. With TOC values around 1.3% and S1 + S2 values up to 2.6 mg/gm, these rocks demonstrate additional generation potential.
5. *Overpressuring is in tight strata.* Permeabilities ranging from 0.18 to 0.4 md typify the tight strata and suffice for production, after induced fracturing.

Based on available information (such as a net pay of 100 ft and extensive reservoirs in the South Park thrust sheet), Savant Resources (Denver, Colorado, written communication, 1999) calculated gas reserves of 1.4-2.3 TCF in the Apache Creek play. Depth to the Apache Creek is 11,150 feet in the Hunt well and varies widely ([Figure 84](#)) ([Wellborn, 1977](#)). Similar thrusts containing the prospective horizon at the required depth could create additional prospects. Notable secondary targets include the Fox Hills Sandstone, the Upper Transition Member of the Pierre Shale, the Niobrara Formation, the Frontier Sandstone, the Dakota Group, and the Garo (Entrada) Sandstone ([Figure 82](#)). Although South Park has had no production to date, a blow-out in the Pierre Shale and hydrocarbon seeps (Elkhorn Thrust, Three Mile Seep, and Willow Creek Pass) indicate a potential for an unconventional deep gas play. Total organic carbon (C) content for the Pierre Shale ranged from 0.1 to 1.5% ([Barker et al., 1996](#); [Savant Resources LLC Report, 1999](#)), and 1.4 to 2.1% for the Mowry Shale ([Aldy, 1994](#)).

Since the Apache Creek Formation also exists in North and Middle Park, basin-centered gas plays may potentially occur in those basins as well.

KEY ACCUMULATION PARAMETERS

Identification

Rocky Mountains and Northern Great Plains Province, Colorado Park Basins; unconventional basin-centered gas play, Upper Cretaceous Pierre Shale (Apache Creek Sandstone) through Jurassic Entrada.

Geologic Characterization of Accumulation:

- a. Source/reservoir** **Source Rocks:** organic-rich layers of the Niobrara ([Maughan, 1989](#)) and the Sharon Springs Member of the Pierre Shale. ([Gautier et al., 1984](#)). **Primary reservoirs:** Upper Cretaceous Apache Creek Sandstone and calcareous shales of the Niobrara. **Secondary reservoirs:** Cretaceous Fox Hills Sandstone, Upper Transition Member of the Pierre Shale, Niobrara Fm, Frontier Sandstone, Dakota Group, and Jurassic Entrada Sandstone.
- b. Total Organic Carbons (TOCs)** Pierre Shale 0.1 to 1.5% ([Barker, 1996](#)) and 1.3% ([Savant Resources LLC Report, 1999](#)); Mowry Shale 1.4-2.1% ([Aldy, 1994](#)).
- c. Thermal maturity** R_o of Pierre and Niobrara ranges from 1.3 to 1.4.
- d. Oil or gas prone** Gas prone.
- e. Overall basin maturity** Because of several periods of Laramide volcanism, certain areas of the basins such as Cameron Pass may be overmature; but this is generally not a problem ([Maughan, 1988](#)).
- f. Age and lithologies** North Park contains Permian through Tertiary sandstones, shales, and volcanoclastics, with lesser amounts of carbonates and marls. South Park contains a thick sequence of Paleozoic arkosic sandstones, carbonates, and shales.
- g. Rock extent/quality** The shoreline sands of the Apache Creek appear throughout the 27 wells in South Park and have yet to be studied in North Park. Niobrara is present throughout the Park Basins; both are of tight reservoir quality. Niobrara and Pierre source rocks also occur basin wide and have adequate TOC and vitrinite reflectance values.
- h. Potential reservoirs** Minor production in North Park Basin ([Maughan, 1988](#)) in both the Pierre and Niobrara.
- i. Major traps/seals** Pierre and Niobrara shales or any of the numerous thrust faults such as the Elkhorn or the South Park serve as physical seals. Pressure seals occur around a depth of 10,000 ft.
- j. Petroleum generation/migration models** In-situ generation is the accepted model.
- k. Depth ranges** Minimum depth of 10,000-20,000 ft.
- l. Pressure gradients** 0.52 psi/foot ([Savant Resources LLC Report, 1999](#))

**Production and Drilling
Characteristics:**

- a. Important fields/reservoirs** The only production is in North Park Basin. Niobrara fractured shale production occurs at Canadian River, Coalmont, Carlstrom, Grizzly Creek, Johnny Moore Mountain, North and South McCallum, Michigan River, and Delaney Butte fields. Pierre sand production is small and limited to North and South McCallum fields.
- b. Cumulative production** 277.9 MBO and 156 MMCFG from the Niobrara ([Colorado Oil and Gas Conservation Commission, 1997](#)) and 1.4 MMCFG and 10.5 MBO from the Pierre ([Maughan, 1988](#))

**Economic
Characteristics:**

- a. Inert gas content** Gas at North and South McCallum fields measures 95% CO₂ ([Carpen, 1957](#)). This may be a local phenomenon where igneous intrusions have carried CO₂ through the normal faults associated with these fields ([Biggs, 1957](#)). [Savant Resources LLC \(report, 1999\)](#) has sampled pipeline-grade gas (1021 Btu) in the Apache Creek Sandstone. There is very little test data of the Niobrara, but one test at Delaney Butte shows a low Btu of 212 ([Wellborn, 1983](#)).
- b. Recovery** Recoveries around 2 TCF are only hypothetical at this point and will be a function of permeability and porosity combined with natural and induced fracturing.
- c. Pipeline infrastructure** Public Service of Colorado and Colorado Natural Gas pipelines are currently in the basin.
- d. Exploration maturity relative to other basins** Immature; sparsely drilled.
- e. Sediment consolidation** Most rocks are well indurated
- f. Porosity/completion problems** Natural fractures and overpressuring enhance flow for tight sandstones and calcareous shales. Hydraulic fracturing is probably essential to develop this play.
- g. Permeability**
- h. Porosity**

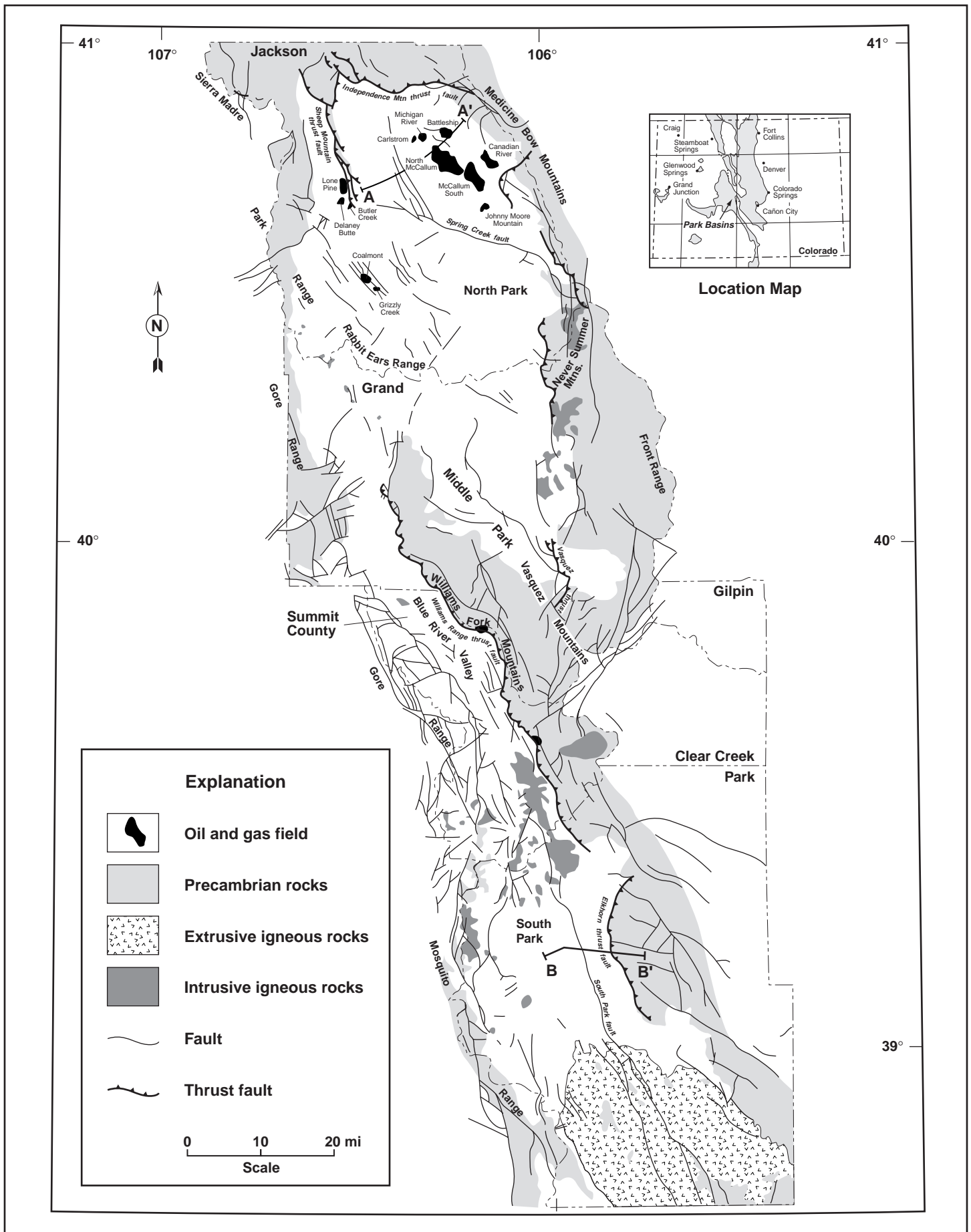


Figure 81. Generalized geologic map of the Colorado Park basin province showing locations of cross sections A-A' (Figure 83) and B-B' (Figure 84). After [Maughan \(1989\)](#).

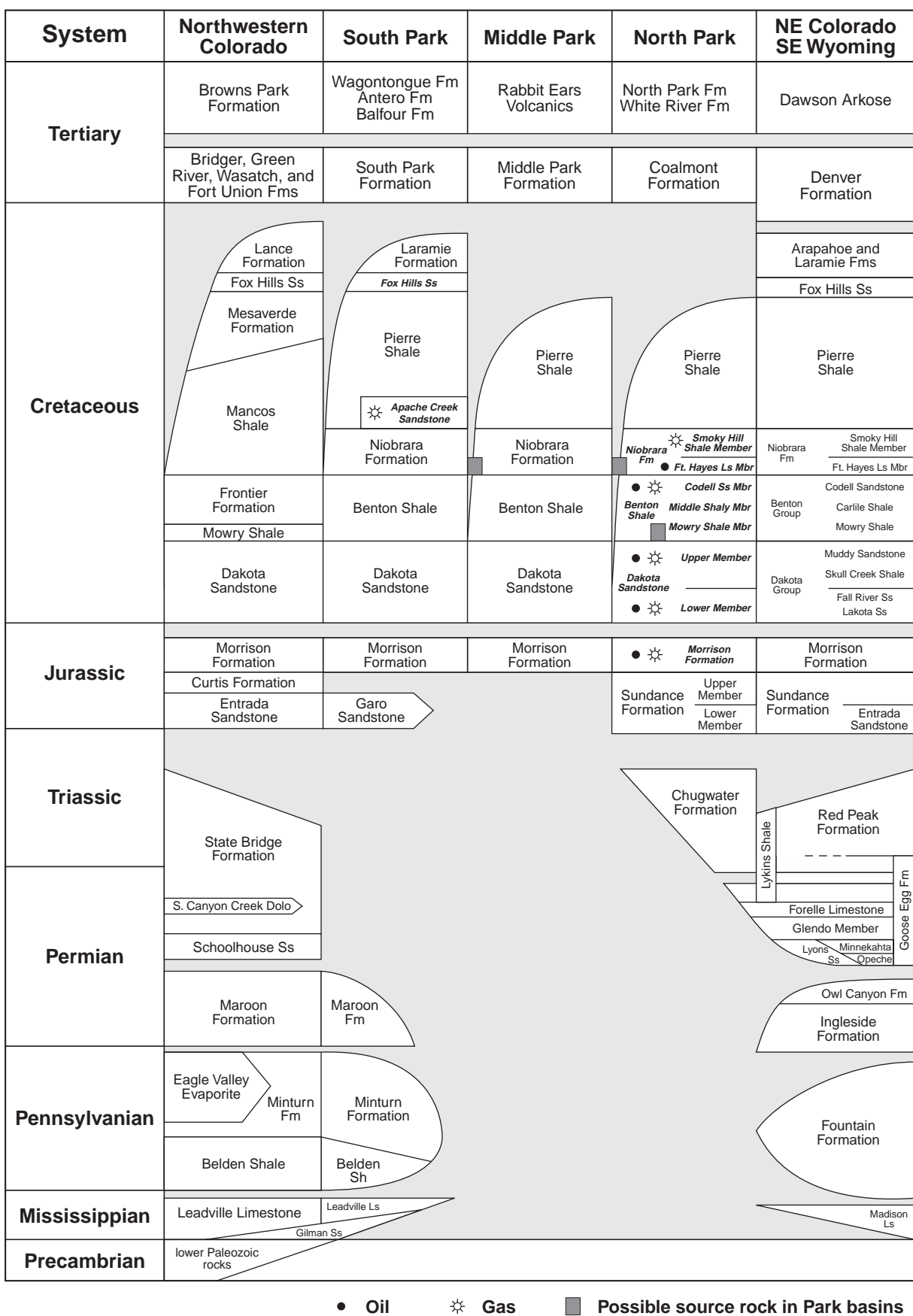


Figure 82. Stratigraphic column of Colorado Park basins showing source rock and reservoir potential. After Wandrey et al. (1996).

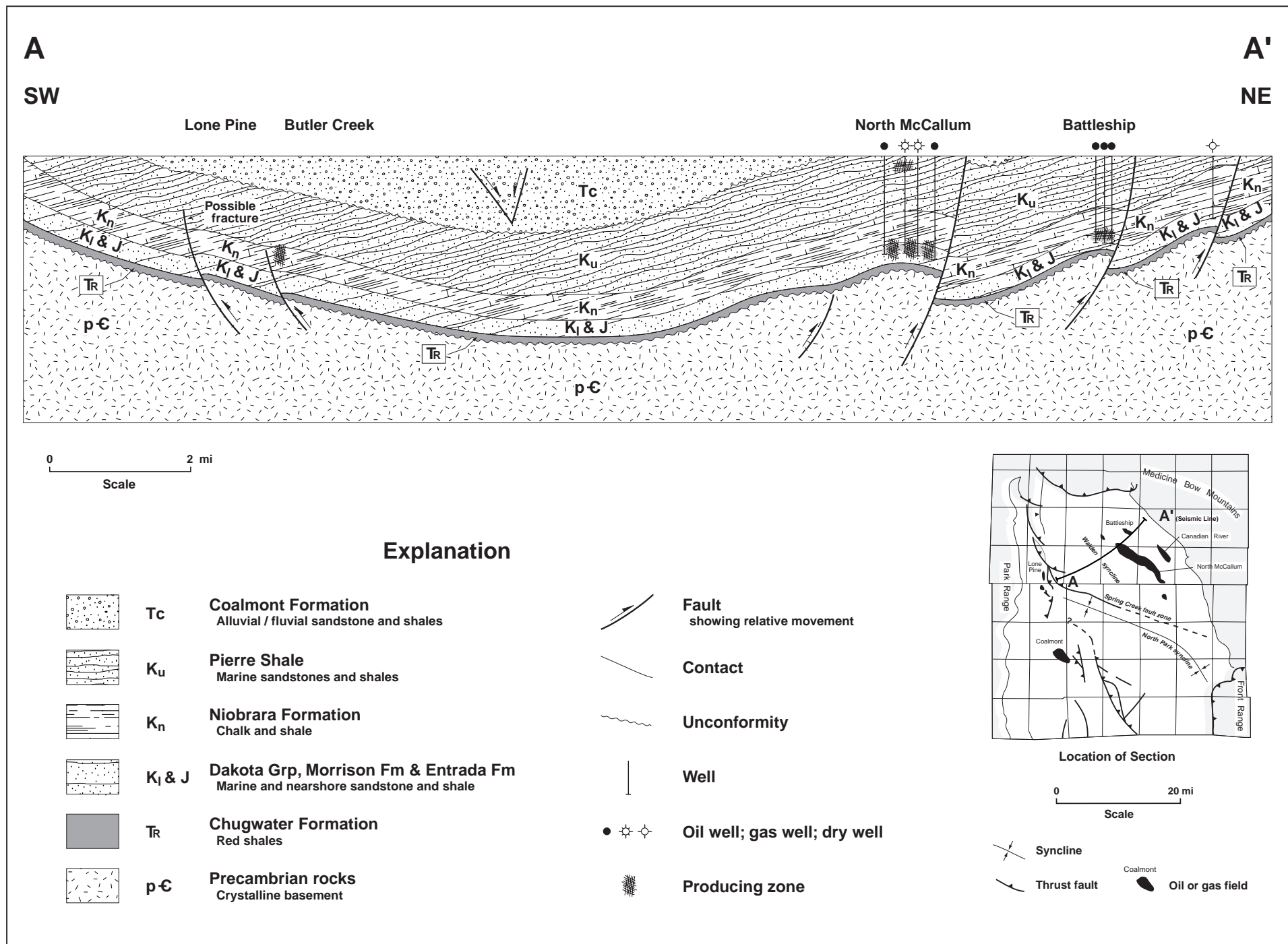


Figure 83. Generalized cross section A-A' of North Park basin, Colorado. Location shown on [Figure 81](#). After [Lange and Wellborn \(1985\)](#).

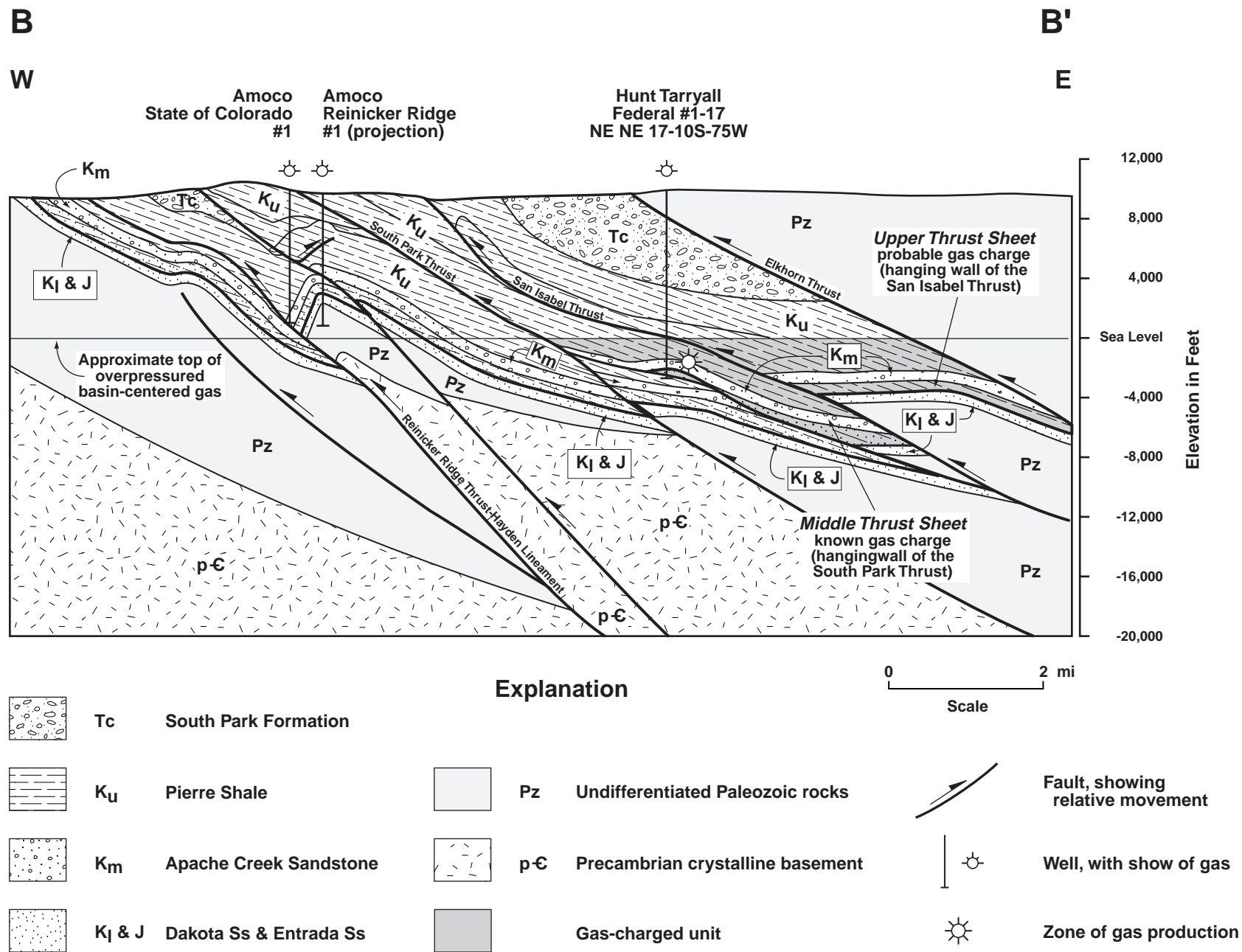


Figure 84. Generalized cross section B-B' of South Park basin, Colorado. Location shown on [Figure 81](#). After [Savant Resources LLC \(1999\)](#).

PERMIAN BASIN (ABO FORMATION)

GEOLOGIC SETTING

The Permian Basin of west Texas and eastern New Mexico covers about 76,250 square miles of the southwest part of the North American mid-continent craton (Frenzel et al., 1988). Figure 85 shows the location and generalized structure of the area. This part of the craton remained exposed until Late Cambrian, when marine transgression formed the Tobosa Basin and filled it mainly with carbonate and fine-grained clastic sediments. The Tobosa Basin was relatively stable until the Late Mississippian, when structural deformation began forming the Matador Uplift, Central Basin Platform, and Diablo Platform. By the Early Pennsylvanian, the Tobosa Basin had broken up into the main elements making up the present day Permian Basin: Northwest Shelf, Delaware Basin, Central Basin Platform, Midland Basin, Val Verde Basin, and Eastern Shelf (Frenzel et al., 1988). Pennsylvanian strata of the basin consists of marine and paralic sandstones, shales, and carbonates.

A final structural pulse deformed the Central Basin and Diablo Platforms in the Early Permian (Wolfcampian). Permian sedimentation filled the Delaware and Midland Basins with deep-water carbonates and shales, basin-margin reef carbonates, evaporites, and red-bed sequences. Permian strata contain most of the hydrocarbon reserves within the basin. Since the Triassic, the Permian Basin has remained tectonically stable.

HYDROCARBON PRODUCTION

Figure 86 shows stratigraphic columns for various basins and platforms in the area. Originally assigned to a Permian (lower Leonardian) red-bed sequence in the Northwest Shelf, the Abo Formation has also been applied to dolomitized carbonates along the northern margins of the Delaware Basin and the Central Basin Platform. The age-equivalent strata in the Central Basin Platform and in the Delaware and Midland Basins have produced hydrocarbons historically. In the Midland Basin, Abo age-equivalent and mature Spraberry Trend covers hundreds of square miles and has produced over 1,388 BCF of gas plus associated condensate (Bebout and Garret, 1989).

Production from the Abo Formation derives from two plays: platform carbonates and fluvial/deltaic sandstones (Figure 87). Most platform-carbonate production comes from the Abo reef trend (Figure 85). The reef reservoirs are stratigraphic traps with clean, white-tan-gray, fine to coarsely crystalline dolostones. Porosity is secondary, consisting of vugs, vertical fractures and intercrystalline pores. Cumulative production from the reef reservoirs was 456 BCFG as of December 31, 1990. A smaller shelf sub-play also exists, and consists of dolomitized back-reef sediments having irregularly distributed porosity and permeability. Traps are low-relief anticlines that have produced 227 BCFG through 1990.

The Abo fluvial/deltaic sandstone is a tight gas play on the Northwest Shelf. Production comes from lenticular, red, very fine to fine grained, silty, arkosic arenites (Broadhead, 1993a, c). A clay-hematite matrix has reduced the primary porosity. Deep-seated faults that tap into older Paleozoic source beds have charged these reservoirs. The three main fields have produced 273 BCFG from stratigraphic traps as of December 31, 1990.

EVIDENCE FOR BASIN-CENTERED GAS

Neither of the two Abo plays are basin-centered. The carbonate play rings the Permian basin margin, and the sandstone play is confined to the northern Northwest Shelf area (Figure 87). However, both plays have anomalous pressure gradients associated with them. The fluvial/deltaic sandstones show a significant underpressure to producing fields (Broadhead, 1993c). The single shelf-carbonate sub-play field has a normal pressure gradient. Abo reef carbonates display a trend: near-normal pressure gradients exist in the south and become underpressured northward (Broadhead, 1993b). Similar south-to-north underpressure gradients are visible in data from the underlying Wolfcamp Formation, overlying Yeso Formation, and basinal-equivalent Bone Spring Formation (Broadhead, 1993a):

Unit or Lithology	Depth (ft)	Pressure Gradient (psi/ft)	Temperature (°F)
Yeso Fm.....	5,000 – 7,030.....	0.263 – 0.495.....	105 – 122
Bone Spring Fm.....	5,480 – 9,700.....	0.343 – 0.428.....	128 – 180
Abo sandstones.....	2,830 – 4,180.....	0.295 – 0.387.....	101 – 114
Abo reef carbonates.....	6,020 – 8,650.....	0.286 – 0.430.....	109 – 140
Wolfcamp Fm.....	8,020 – 13,250.....	0.354 – 0.843.....	129 – 193

KEY ACCUMULATION PARAMETERS

Identification

Southwestern U.S., west Texas and eastern New Mexico. Lower Permian Abo Formation

Geologic Characterization of Accumulation:

- | | |
|---|---|
| a. Source/reservoir | Source intervals: poorly documented and appear to be largely speculative in the literature. Major sources are thought to occur in Permian basinal shales and carbonates (Wolfcamp and Bone Springs), Permian shelf shales and low energy carbonates (Wolfcamp and Abo/Wichita-Albany), Pennsylvanian limestones and shales, and Upper Devonian (Woodford)–Mississippian (Barnett) shales (Broadhead, 1993a ; Hanson et al., 1991).
Reservoir intervals: Abo platform carbonates are mainly dolomite, Abo fluvial/deltaics are mainly red-bed sandstones. |
| b. Total Organic Carbons (TOCs) | 1-3% for Midland Basin Spraberry black shales (Ramondetta, 1982) |
| c. Thermal maturity | Kerogen Type: algal and amorphous for Midland Basin Spraberry black shales (Ramondetta, 1982) |
| d. Oil or gas prone | Both oil and gas prone. |
| e. Overall basin maturity | Mature |
| f. Age and lithologies | Permian Abo platform carbonates-lower Leonardian, Permian Abo fluvial/deltaic sandstones-lower Leonardian (Broadhead, 1993b, c). |
| g. Rock extent/quality | Source rock occurs basin wide, Abo platform carbonate reservoir rock has a distribution which follows the margin of the Delaware and Midland Basins and the Central Basin Platform, Abo fluvial/deltaic sandstones are found north of the barrier reef trend on the Northwest Shelf. |
| h. Potential reservoirs | |
| i. Major traps/seals | Abo platform carbonates: anticline/dome and lateral changes in porosity and/or permeability because of changes in depositional environment; Abo fluvial/deltaic sandstones: stratigraphic trap, but poorly understood (Broadhead, 1993b, c). |
| j. Petroleum generation/migration models | Barber (1979) |
| k. Depth ranges | Abo platform carbonates, 6020-8650 ft; Abo fluvial/deltaic sandstones, 2830-4180 ft (Broadhead, 1993b, c) |
| l. Pressure gradients | 0.263 to 0.843 psi/ft. |

**Production and Drilling
Characteristics:**

**a. Important
fields/reservoirs**

Abo platform carbonates: Brunson South, Corbin, Empire, Lovington, Skaggs, Vacuum, Vacuum North, Wantz, and Kingdom

Abo fluvial deltaic sandstones: Pecos Slope West, Pecos Slope South, and Pecos Slope

b. Cumulative production

Fields/ Reserves	Cumulative Gas (BCF)	Number of Wells	Abandoned Wells	Spacing (acre)
<u>Abo Platform Carbonates</u>				
Brunson South.....	129.1	165.....	12.....	40
Corbin	20.2	33.....	10.....	40
Empire.....	293.6	391.....	47.....	40
Lovington.....	13.0	26.....	43.....	40
Skaggs.....	7.0	6.....	2.....	40
Vacuum.....	129.2	134.....	45.....	40
Vacuum North.....	40.8	284.....	115.....	80
Wantz.....	50.5	144.....	112.....	40
Kingdom.....	51.0	184.....		40
<u>Abo Fluvial/Deltaic Ss</u>				
Pecos Slope West.....	21.4	170.....	18.....	160
Pecos Slope South	20.5	107.....	4.....	320
Pecos Slope	230.8	603.....	11.....	160

Asreen (1990); Broadhead (1993b, c); Frank (1996)

**Economic
Characteristics:**

a. Inert gas content

Abo fluvial/deltaic sandstones: CH₄-86.6%, C₂H₆-4.8%, all other C_xH_x-3.4% N₂-5.22%, CO₂-0.03% (Montgomery, 1983).

Composite Abo data: CH₄-84.0%, C₂H₆-4.7, all other C_xH_x-3.9%, CO₂-0.2%, N₂-6.6%, He-0.2% (Hogman et al., 1993)

b. Recovery

c. Pipeline infrastructure	Very good. There are numerous gas lines in the basin.
d. Exploration maturity relative to other basins	Mature
e. Sediment consolidation	Good to moderate consolidation.
f. Porosity/completion problems	<p>Abo fluvial/deltaic sandstones are classified as tight gas. These reservoirs require acidization and artificial fracturing. Average in-situ permeability is 0.0067 md; average porosity is 12-14% with 9% necessary for economic production. Production operates on a pressure depletion/gas expansion drive. Abo platform carbonates have an irregular distribution of secondary porosity, averaging 6-14% but ranging from 1.5-18.3%.</p> <p>Permeability also has an irregular distribution resulting in poor fluid communication within the reservoir. Permeability averages 1.5-25 md but ranges from 0.1-1,970 md. This play operates on a primary gas-cap expansion drive augmented by secondary gas-cap growth due to pressure dissolution (Broadhead, 1993b). In the Empire field some component of water drive may be operating (LeMay, 1972).</p>
g. Permeability	0.0067 md
h. Porosity	12 to 14%

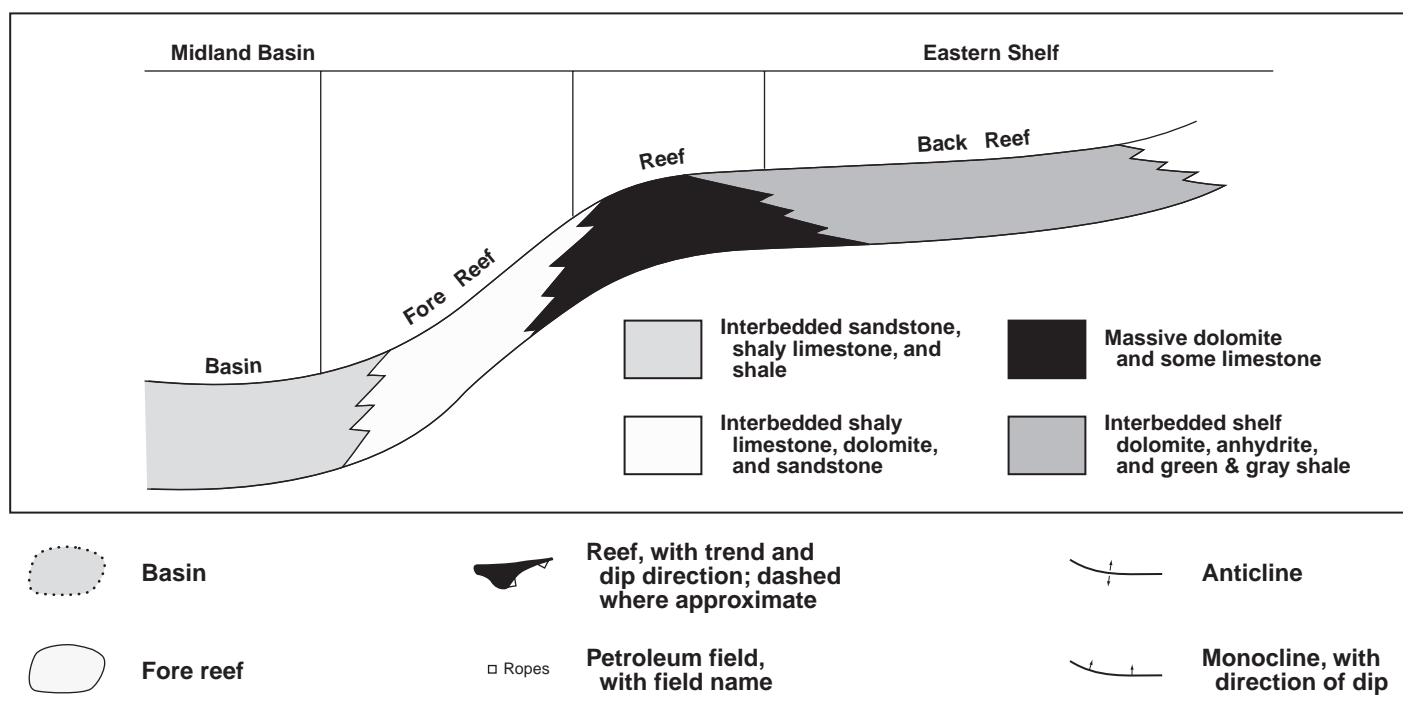
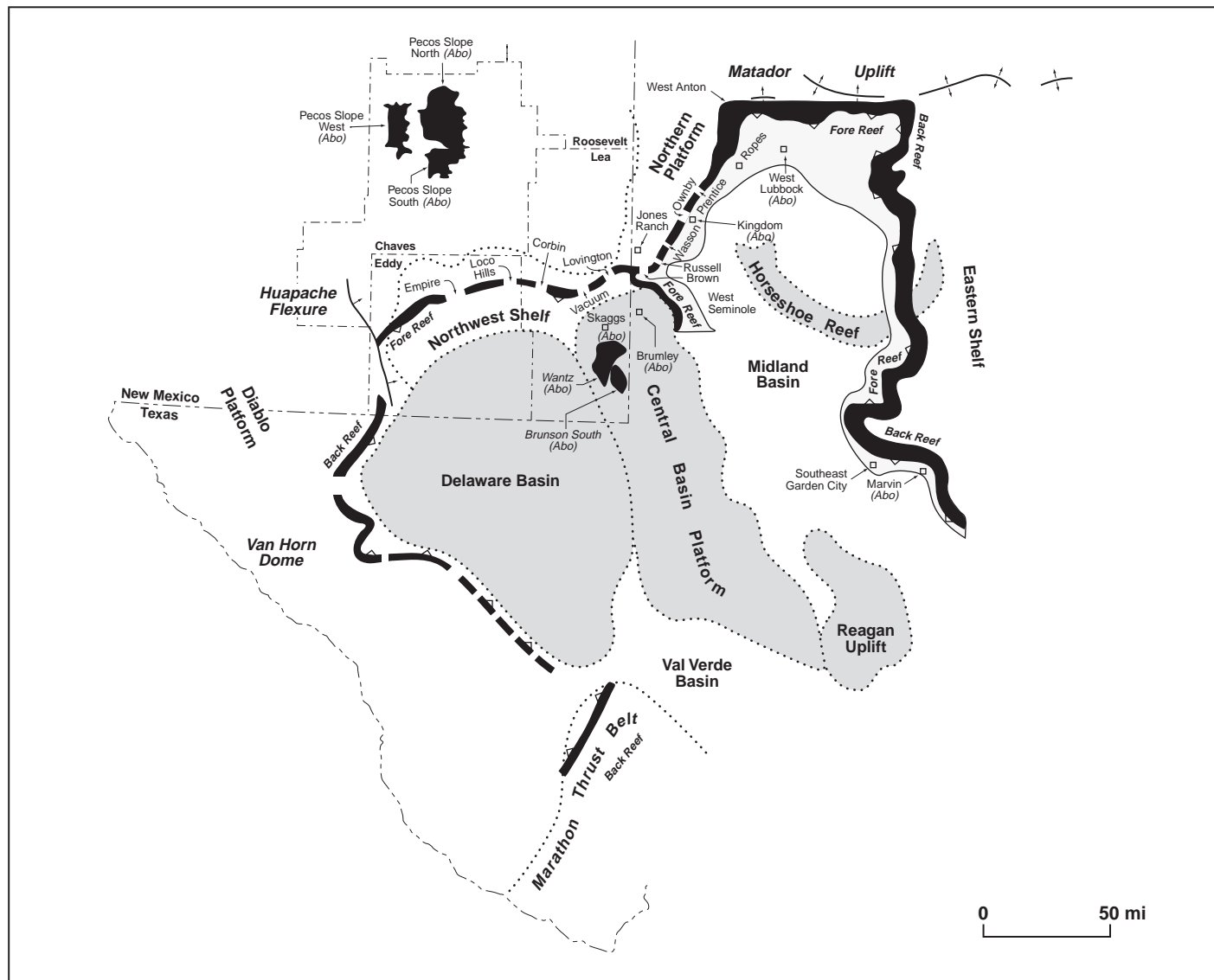


Figure 85. Location map and generalized cross section of part of Permian Basin, west Texas and southeast New Mexico. Map shows Abo-Wichita-Albany Reef trend in the Permian Lower Leonard series. From [Wright \(1979\)](#).

System	Series or Stage	Delaware Basin		Central Basin Platform		Northwest Shelf		Midland Basin				
Quaternary	Recent	Alluvium		Alluvium		Alluvium		Alluvium				
	Pleistocene											
Tertiary	Pliocene to Eocene			Ogallala		Ogallala		Ogallala				
Cretaceous	Gulfian											
	Comanchean	Fredericksburg Ls		Fredericksburg Ls				Washita				
		Trinity	Paluxy ss	Trinity	Paluxy ss			Trinity	Paluxy ss			
Triassic	Upper	Santa Rosa		Dockum	Chinle	Dockum	Chinle	Dockum	Chinle			
					Santa Rosa		Santa Rosa		Santa Rosa			
Permian	Ochoan	Dewey Lake		Dewey Lake		Dewey Lake		Dewey Lake				
		Rustler		Rustler		Rustler		Rustler				
		Salado		Salado		Salado		Salado				
		Castile										
	Guadalupean	Delaware Mountain Group	Lamar Bell Canyon	Whitehorse	Tansill	Whitehorse	Tansill	Whitehorse	Tansill			
			Cherry Canyon		Yates		Yates		Yates			
					Seven Rivers		Seven Rivers		Seven Rivers			
			Queen		Queen		Queen		Queen			
		Brushy Canyon	Word	San Andres	Word	San Andres	Word	San Andres				
			Glorieta	Glorieta	Glorieta	Glorieta						
	Leonardian	Bone Spring	Cutoff Member	Clear Fork	U. Clear Fork	Yeso	Paddock Blinebry Tubb Drinkard	Clear Fork	Upper Leonard			
					Tubb Sand							
			1st B. Spg. Sand		L. Clear Fork							
			2nd B. Spg. Sand		Wichita		Abo		Wichita	U. Spraberry		
			3rd B. Spg. Sand							L. Spraberry		
	Wolfcampian	Wolfcamp		Wolfcamp		Wolfcamp	Husco	Wolfcamp				
	Pennsylvanian	Virgilian		Cisco	Cisco		Cisco		Cisco			
		Missourian		Canyon	Canyon		Canyon		Canyon			
		Desmoinesian		Strawn	Strawn		Strawn		Strawn			
		Atokan		Atoka	Atoka		Atoka		Atoka			
Morrowian		Morrow		Morrow		Morrow		Morrow				
Mississippian	Chesterian	Barnett Shale		Barnett Shale		Barnett Shale		U. Mississippian Ls				
	Meramecian-Osagean	Mississippian Ls		Mississippian Ls		Mississippian Ls		L. Mississippian Ls				
	Kinderhookian	Kinderhook		Kinderhook		Kinderhook		Kinderhook				
Devonian	Upper	Woodford		Woodford		Woodford		Woodford				
	Middle											
	Lower											
Silurian	Upper Niagaran	U. Silurian Shale		U. Silurian Shale		U. Silurian Shale		U. Silurian Shale				
	Lower Niagaran	Fusselman		Fusselman		Fusselman		Fusselman				
	Alexandrian											
Ordovician	Cincinnatian	Montoya		Montoya		Montoya		Montoya	Sylvan Sh			
	Mohawkian	Simpson	Bromide	Simpson	Bromide	Simpson	Bromide	Simpson	Bromide			
			Tulip Creek		Tulip Creek		Tulip Creek		Tulip Creek			
	McLish		McLish		McLish		McLish					
	Oil Creek		Oil Creek		Oil Creek		Oil Creek					
	Joins		Joins		Joins		Joins					
Canadian	Ellenburger		Ellenburger		Ellenburger		Ellenburger					
Ozarkian												
Cambrian	Upper							Wilberns				
								Hickory				
Precambrian												

Figure 86. Stratigraphic column for west Texas-southeast New Mexico area basins. After [Dull and Garber \(1996\)](#).

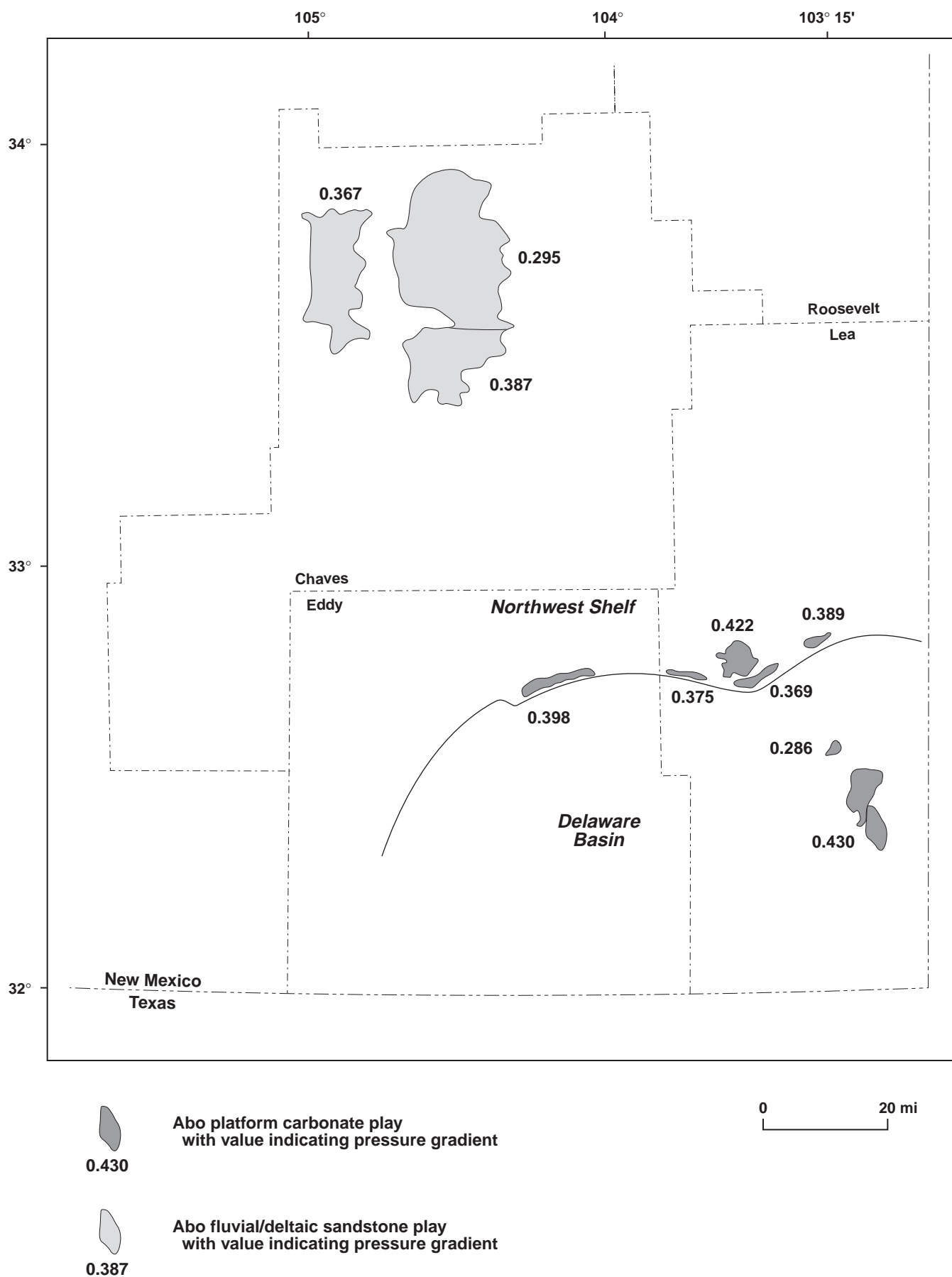


Figure 87. Map showing pressure gradients by field for the Abo platform-carbonate and fluvial/deltaic sandstone plays, southeast New Mexico. Modified from [Broadhead \(1993b, c\)](#).

RATON BASIN

GEOLOGIC SETTING

The Raton basin straddles the Colorado-New Mexico state line in southeastern Colorado and northeastern New Mexico (Figure 88). The Apishapa Uplift and the Wet Mountains separate the Raton from the Denver basin to the north. The Sangre de Cristo Mountains form the western boundary, and the Sierra Grande Uplift limits the east side (Larsen, 1985). The Raton displays an arcuate shape and asymmetric profile—its western flank dips steeply and is highly faulted. Figure 89 shows the post-Paleozoic stratigraphy for the basin; most rocks with hydrocarbon content are Cretaceous in age.

The Raton is the southernmost basin formed during the Laramide orogeny of late Cretaceous to early Tertiary time. Initial Laramide uplift added coarse-grained siltstones, sands and sandy shales to the upper Pierre Shale and lower Trinidad Sandstone stratigraphy (Figures 89 and 90) (Stevens et al., 1992). The stratigraphic succession includes rocks from Precambrian to Miocene and Quaternary ages, but Cambrian through Silurian rocks are absent (Figure 89). A thin Devonian through Mississippian section rests directly on basement rocks. Gromer (1982) notes Raton sediments probably thicken to 25,000 ft at the western edge of the basin. The southern part of the basin does not contain late Cretaceous or Tertiary coal bearing strata.

Intrusive activity began during the Eocene and continued throughout the Oligocene. In the immediate Spanish Peaks area, two stocks and radial dikes and sills intruded the country rock. East-northeasterly trending dikes intruded an area east of the Spanish Peaks (Larsen, 1985). Other igneous bodies include late Tertiary and Quaternary basalt and andesite flows derived from the Raton volcanic field on the southeastern margin of the basin (Larsen, 1985). The plutonic and volcanic activity all contributed to thermal maturation of hydrocarbon source rocks and generated major resources of carbon dioxide.

HYDROCARBON PRODUCTION

Aside from coalbed methane produced from the Vermejo and Raton coals within the past few years, no other commercial hydrocarbon production has occurred. Dolly and Meissner (1977) estimated these coal beds alone generated more than 20 trillion ft³ of gas.

Zones that have oil and gas shows include the Trinidad Sandstone, Pierre Shale, Niobrara chinks and shales, Benton Group (Graneros Shale, Greenhorn Limestone, Carlile Shale and Codell Sandstone), and lower Cretaceous Dakota Sandstone (Figure 89)

EVIDENCE FOR BASIN-CENTERED GAS

Evidence that a basin-centered accumulation might exist within the Raton Basin includes the following:

- 1) a widespread resistivity anomaly pattern in the Trinidad Sandstone (Figure 91) (Rose, et al., 1986). Maximum resistivities in the Raton Sandstone increase with burial depth and near volcanic centers;
- 2) extensive underpressuring (Dolly and Meissner, 1977);
- 3) abundant gas shows found in wells drilled throughout the basin;
- 4) vitrinite reflectance (Ro) reaches a maximum of 1.5, indicating thermal maturity. Figure 92 shows Ro isopleths for the Raton Basin; and
- 5) the Trinidad is the seaward equivalent of the San Juan Basin's Pictured Cliff Sandstone, a classic basin-centered accumulation (C. Spencer, U.S. Geological Survey, 2001, written communication).

KEY ACCUMULATION PARAMETERS

Identification

Rocky Mountain, Raton Basin, early to late Cretaceous

Geologic Characterization of Accumulation:

- | | |
|---|---|
| a. Source/reservoir | Cretaceous Dakota Sandstone and Pierre Shale through lower Paleocene Raton formation |
| b. Total Organic Carbons (TOCs) | 2.95% in the Trinidad area, 1.34-2.43% in the Raton area, 0.3 and 5.37% at Huerfano Park, west of Walsenberg (Sharon Springs member of the Pierre Shale) (Gautier et al., 1984) |
| c. Thermal maturity | $R_o = 1.5\%$ near the center of the basin to 0.7% near the southern, eastern and northern basin margins, along the Trinidad Sandstone outcrop (vitrinite values from Vermejo coals) (Figure 92) (Stevens et al., 1992) |
| d. Oil or gas prone | Gas prone. |
| e. Overall basin maturity | Most of the basin is mature. The outcrop of the Trinidad sandstone appears to fall within the 0.7-0.8 R_o (Vermejo coals) range. |
| f. Age and lithologies | early to late Cretaceous and early Paleocene; Graneros Sh, Greenhorn Ls, Carlile Sh, Niobrara Chalk/Shale/Marl, Pierre Sh, Trinidad SS, Vermejo and Raton shales, sands and coals |
| g. Rock extent/quality | apparent basin-wide source and reservoir-rock distribution |
| h. Potential reservoirs | Trinidad SS, Pierre Sh, Niobrara Chalk/Sh/ Marl, Codell Sh |
| i. Major traps/seals | Pierre Shale, Vermejo Fm |
| j. Petroleum generation/migration models | In situ generation of gases from intermixed source rock (coals, shales and chinks)/reservoir rock facies. Weimer's Denver basin "cooking pot" model may be applied in this basin as well (Weimer, 1996). |
| k. Depth ranges | 5000+ ft Trinidad sandstone in the center of the basin to 1500 ft on the eastern flank. Dakota Sandstone is $\pm 15,000$ ft in the center. |
| l. Pressure gradients | Underpressured at shallow levels, Trinidad and upper Pierre = 0.33 psi/ft; Raton Formation (1630-1760 ft) = 0.25 psi/ft in the northern part of the basin (Rose et al., 1986). Possible deep overpressure in Dakota-Niobrara? |

Production and Drilling Characteristics:

- | | |
|---------------------------------------|---|
| a. Important fields/reservoirs | No producing fields except for shallow Raton and Vermejo coal-bed methane development, and major CO ₂ field. |
| b. Cumulative production | none |

Economic Characteristics:

- | | |
|---|---|
| a. Inert gas content | The chemical content of the coal gases should approximate that expected from nearby underlying rocks. Heating value of the Raton and Vermejo coal gases range from 997-1272 btu/cu ft, with nitrogen ranging from 0.1–0.8%. |
| b. Recovery | Carbon dioxide content ranges from 0 – 1.1% (Scott, 1993).
No current commercial gas production exists except from coal seams. |
| c. Pipeline infrastructure | Currently poor, but will be developed with increasing coalbed methane drilling. |
| d. Exploration maturity relative to other basins | Immature |
| e. Sediment consolidation | Consolidation/porosity reduction occurs with depth of burial, especially in the Niobrara Chalk (Pollastro and Martinez, 1985). |
| f. Porosity/completion problems | Chalks and other tight (low permeability) rocks have potential to produce where they are naturally fractured (Florence-Canon City Field to the north in the Canon City Embayment). Low pressures and water sensitive clays may cause additional evaluation problems (Dolly and Meissner, 1977). |
| g. Permeability | Trinidad Sandstone, less than 0.1 to 344 md; shales and chalks, less than 1.0 md. |
| h. Porosity | Trinidad Sandstone, 12%; shales and chalks, highly variable. |

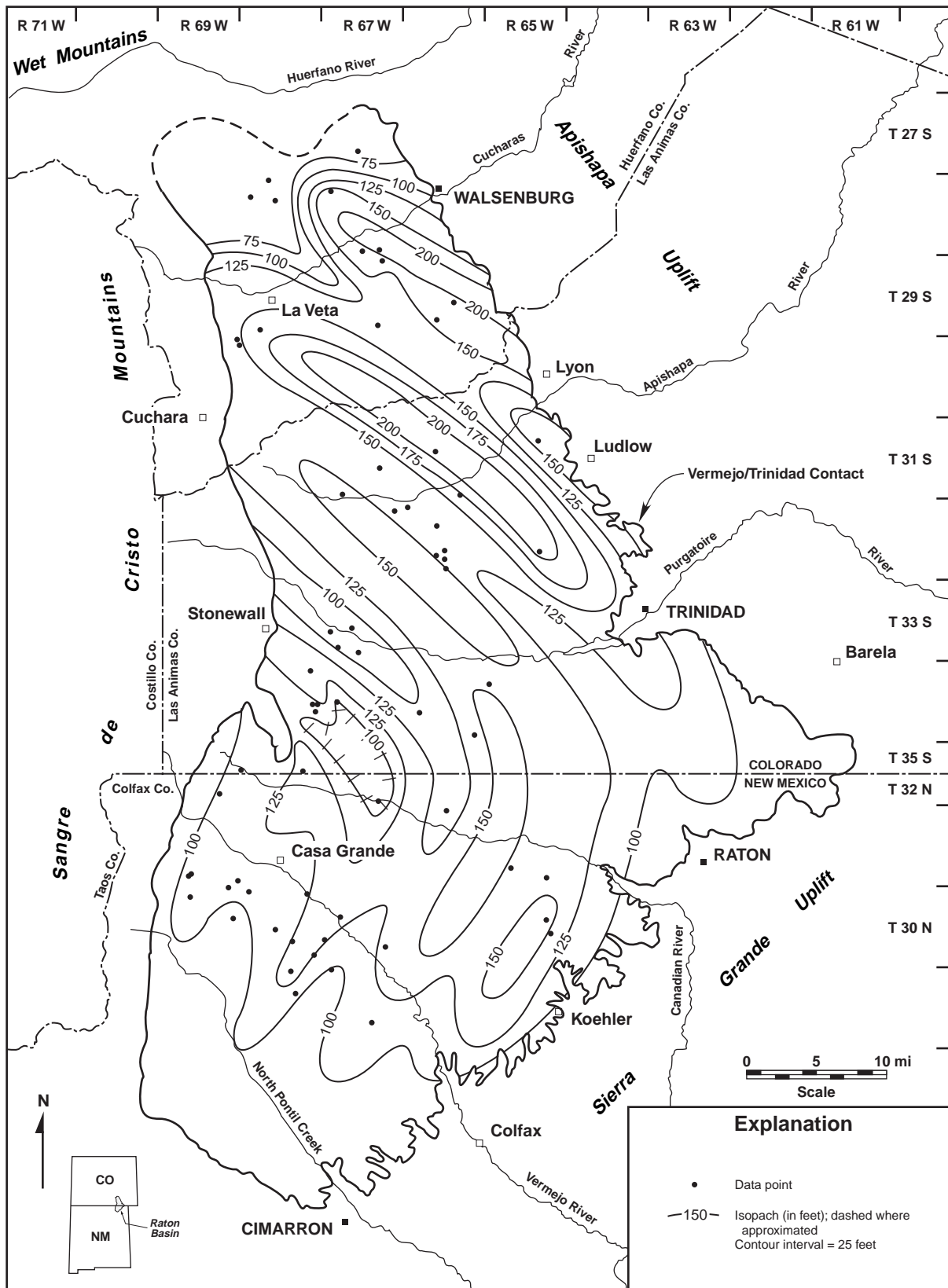
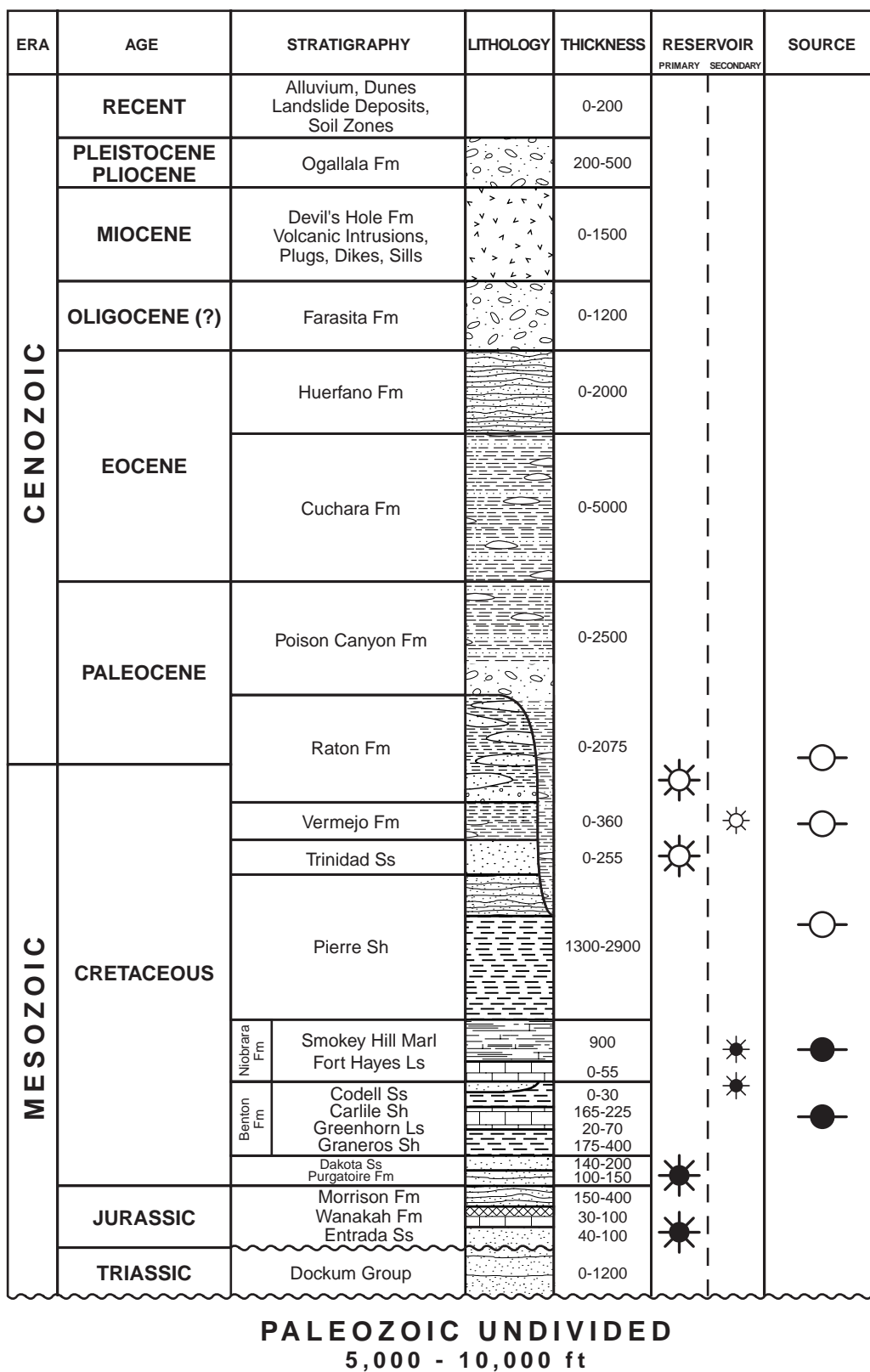


Figure 88. Isopach of Trinidad Sandstone in Raton Basin (using gamma ray cut-off value of 70-80 API units). After [Stevens et al. \(1992\)](#).



EXPLANATION

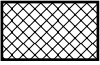



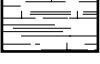



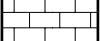



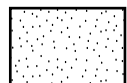
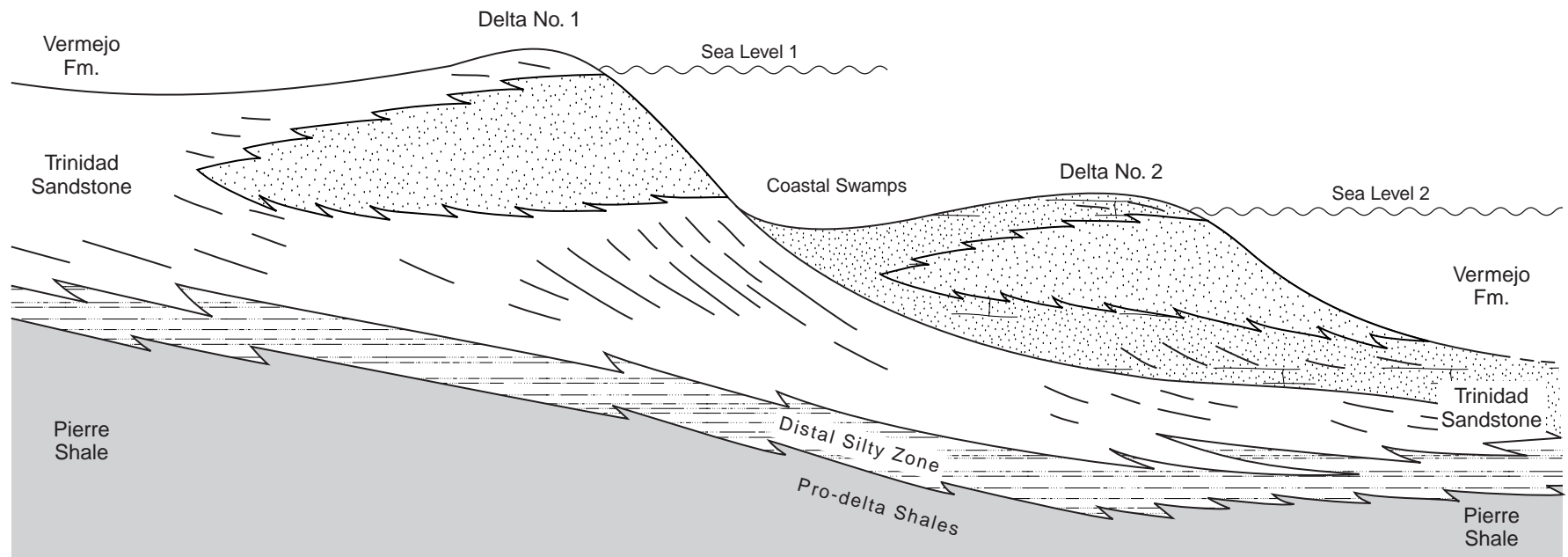
	Anhydrite		Shale		Shaly Sandstone		Undifferentiated Volcanic Rocks
	Marlstone		Sandy Shale		Sandstone		Gas
	Limestone		Pebbly Mudstone		Pebbly Sandstone		Oil

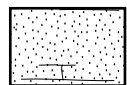
Figure 89. Columnar section of post-Paleozoic rocks in the Raton basin. After [Rose et al. \(1986\)](#), and [Dolly and Meissner \(1977\)](#).

SW

NE



"High Energy" Sandstone



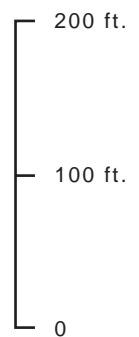
Deltaic Sediments



Siltstone



Shale



Datum: Interpreted sea level during deposition of Delta No. 1

Figure 90. Generalized cross section showing Trinidad Sandstone depositional environments in the Raton Basin. After [Rose et al. \(1986\)](#).

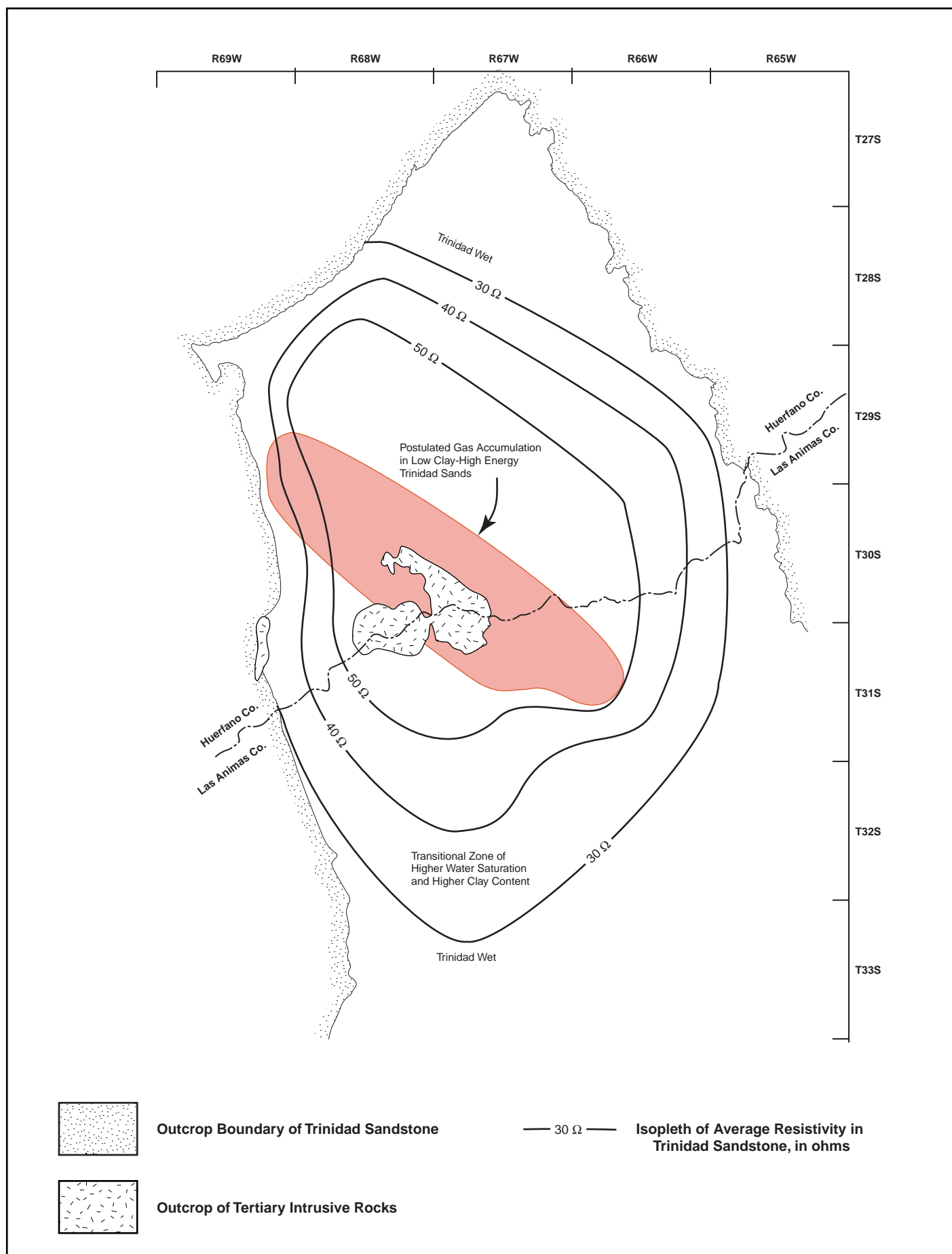


Figure 91. Delineation of postulated basin-centered gas accumulation in Trinidad Sandstone. After [Rose et al. \(1986\)](#).

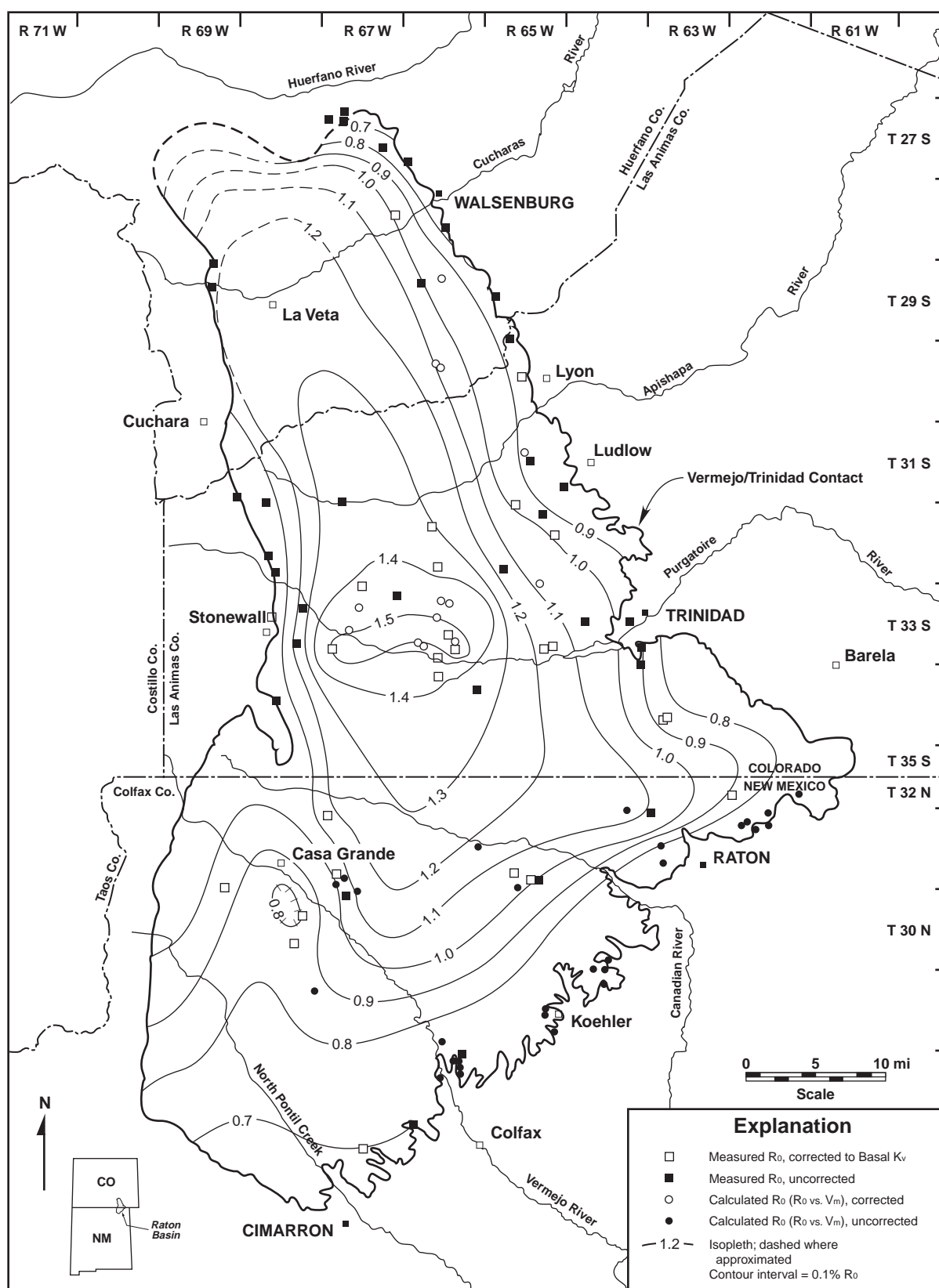


Figure 92. Isopleth of vitrinite reflectance in Raton Basin, adjusted to basal Vermejo Formation. After [Stevens et al. \(1992\)](#).

RIO GRANDE RIFT (ALBUQUERQUE BASIN)

GEOLOGIC SETTING

The late Cenozoic Rio Grande Rift extends from the upper Arkansas Valley in Colorado, south through central New Mexico and the Big Bend area of Texas into the state of Chihuahua, Mexico (Figure 93) (Molenaar, 1996). The rift separates the North American Craton from the Colorado Plateau. Opening of the rift may have resulted from clockwise rotation of the Colorado Plateau about an Euler pole located in northeast Utah (Keller and Cather, 1994).

The rift system developed in terrain elevated during Laramide time because of crustal thickening (Keller and Cather, 1994). Initial sedimentation commenced in late Oligocene to early Miocene, with rapid extension beginning in middle to late Miocene. Miocene extension in the north-central part of the rift was left-oblique. The amount of extension decreases in the southern half of the rift, which expands in width and becomes a series of parallel basins with intrarift uplifts and tilted fault blocks.

The rift contains over thirty named basins (Figure 93), most of which are first-order half-grabens; basin asymmetry shifts across accommodation zones (Chapin and Cather, 1994). Drilling and geophysical exploration continue to reveal and delimit new sub-basins. To date, tentative exploration has focused on two major basins, the San Luis in southern Colorado, and the Albuquerque basin in northwestern New Mexico.

The deepest part of the rift occurs along the east side of the San Luis basin. The San Luis basin consists of two half-grabens (the western Monte Vista graben and the eastern Baca) with a central horst between them.

The Albuquerque basin lies between the Sandia and Manzano Mountains to the east and the Ladron and Lucero uplifts to the west. The basin contains two half-grabens separated by the northeast-southwest trending Tijeras fault zone (Figure 94). The west-dipping northern graben contains a listric fault system (Figure 95); the east-dipping southern graben exhibits high-angle normal faults (Figure 96). Pre-existing Precambrian basement structures may have controlled Tertiary structures (Russell and Snelson, 1994).

Basin fill consists of poorly indurated alluvial fans, axial river sands and gravels, playa deposits, eolian dune sands, and pyroclastic volcanics of the Santa Fe Group. The San Luis basin contains at least 7,000 ft of fill; Mesozoic sediments lie beneath the Tertiary valley deposits. Over 14,000 ft of sediment fills the Albuquerque basin. Brister and Gries (1994) reported coal occurrence within the Santa Fe Group in the San Luis basin. Figure 97 shows the general stratigraphy for the Albuquerque Basin and Rio Grande Rift zone.

HYDROCARBON PRODUCTION

Most exploration has concentrated on the San Luis and Albuquerque basins. In 1993 Lexam Exploration drilled 42 gold exploration holes into the east side of the Baca graben at the base of the Sangre de Cristo Mountains; 27 wells showed oil at depths between 300 and 800 ft.. Several test wells had gas shows within the Santa Fe Group, and one well reportedly intercepted coal within the Santa Fe Group. Six of the exploration wells penetrated a previously unknown Cretaceous section. Drilling in the Albuquerque basin has taken place in both north and south grabens (Figures 95 and 96). Of the 60 or so exploratory wells drilled, only two have penetrated the Mesozoic section (Black, 1998).

Total organic carbon (TOC) content for the Cretaceous shales of the eastern San Luis basin ranges from 1.63 to 7.31% (Morel and Watkins, 1997). For the Albuquerque basin's north graben, Broadhead et al. (1998) reported TOC values of about 1.4 to 10.1% in the Mancos Shale and 22.3 to 28.9% in the upper Mesaverde coals.

EVIDENCE FOR BASIN-CENTERED GAS

Possible basin-centered gas might occur within the Cretaceous section of the Baca Graben in the San Luis Basin and in the Cretaceous and Jurassic sections of the Albuquerque basin. The areal extent of any potential accumulation within the Mesozoic sediments remains unknown. Other basins within the Rockies with a similar Cretaceous section such as the Piceance Basin do host basin-centered gas accumulations.

KEY ACCUMULATION PARAMETERS

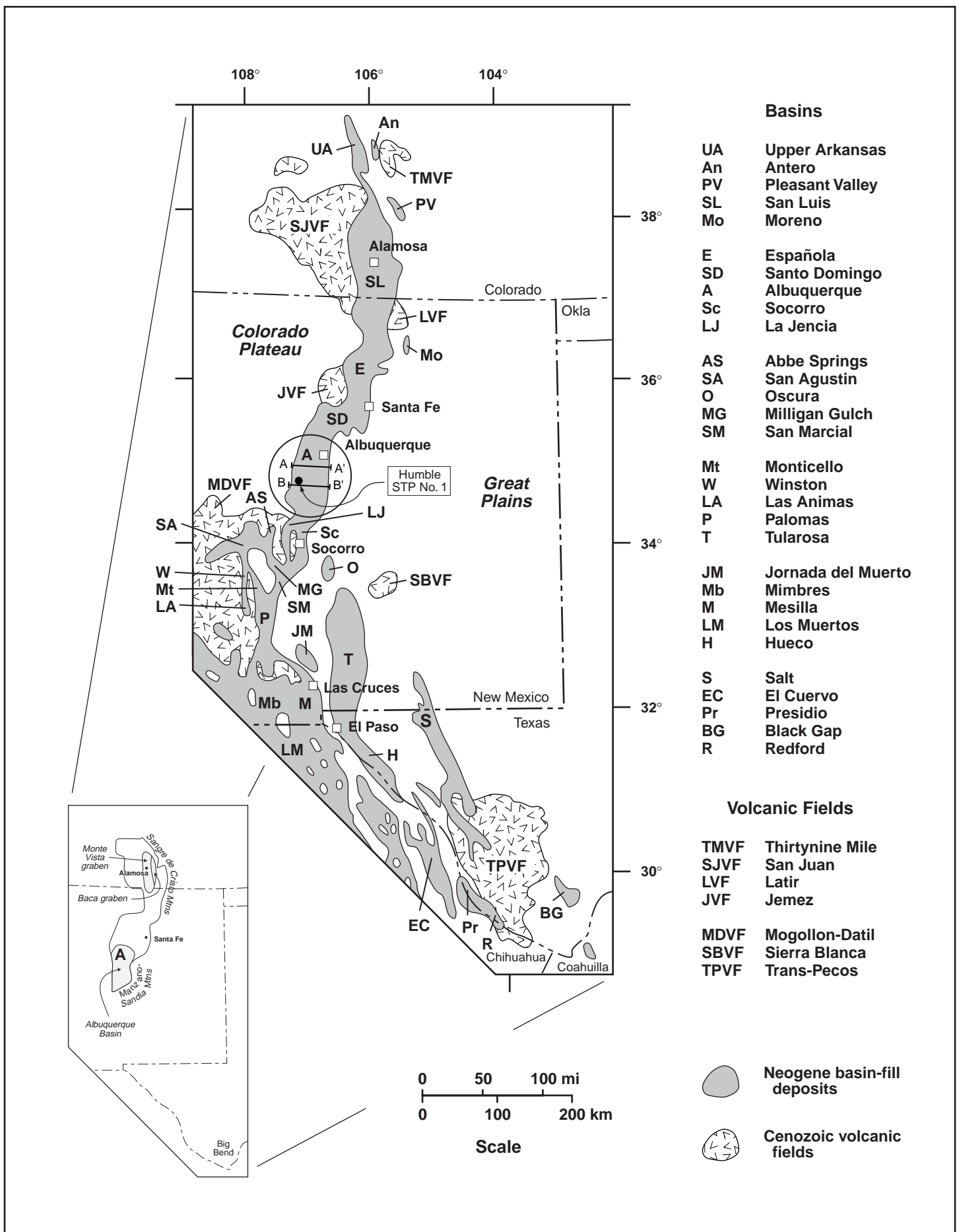
Identification

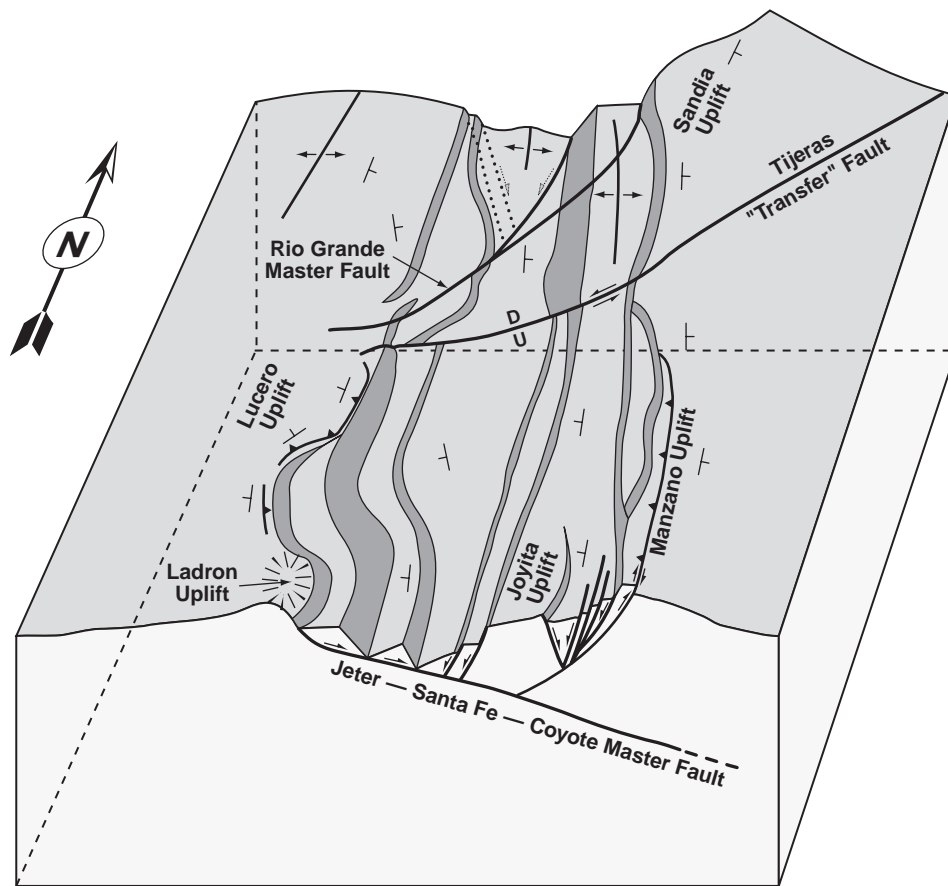
Rio Grande Rift (Albuquerque-Santa Fe Rift, Province 023–Molenaar, 1996), basin-centered gas play in Cretaceous sandstones of San Luis and Albuquerque Basins

Geologic Characterization of Accumulation:

- | | |
|---|---|
| a. Source/reservoir | Cretaceous shales (Mancos) of San Luis Valley and Albuquerque basins, Todilto Limestone additional source in Albuquerque Basin. Dakota in both basins with Morrison in Albuquerque Basin. |
| b. Total Organic Carbons (TOCs) | San Luis Basin: Cretaceous shales of eastern basin, 1.63 to 7.31% (Morel and Watkins, 1997). Some coal had been found within the Santa Fe Group in the San Luis Basin (Brister and Gries, 1994). |
| c. Thermal maturity | Albuquerque basin: Mancos shale (north graben) – 1.39 to 10.1%, upper Mesaverde coals (also north graben) – 22.25–28.85% (Broadhead et al., 1998).
San Luis Basin: Modeling by Morel and Watkins (1997) indicated source rocks entered oil and gas window 10 to 15 Ma.
Albuquerque basin: levels of maturity on basin flanks from 9.0 to 2.0 %R _o , and Cretaceous section of Humble SFP #1 (sec. 18, T6N, R1W) from 12.0 to 14.0 %R _o (condensate and wet gas) (Black, 1982). |
| d. Oil or gas prone | Both oil and gas prone; type III kerogens limited; type II kerogen found in San Luis Basin. |
| e. Overall basin maturity | San Luis Basin: moderate to mature. Albuquerque Basin: mature to overmature. Anthracinite reported in Cretaceous sediments in Humble SFP #1 (Black, 1982). Play confined to shallower and less mature basin flanks. |
| f. Age and lithologies | Cretaceous shales, sandstone for both basins. Albuquerque Basin has Pennsylvanian Todilto limestones in addition to Jurassic Morrison and Entrada sandstones (Figure 97). |
| g. Rock extent/quality | In the eastern part of San Luis Basin, Cretaceous deposits are up to 45 mi long, 18 mi wide and 3,000 ft thick (Morel and Watkins, 1997). In the Albuquerque Basin, the Cretaceous extends across townships T2–3N and R2W–4E (Black, 1982). The Cretaceous section consists of marine shales, marginal marine and fluvial channel sandstones. |
| h. Potential reservoirs | At the present time there is no hydrocarbon production within either the San Luis or Albuquerque Basins. |
| i. Major traps/seals | Stratigraphic traps within the sandstones are possible. The overlying Cretaceous marine shales and thinner shales within the sandstones provide seals. Jurassic shales are potential seals within the Albuquerque Basin. |
| j. Petroleum generation/migration models | Structural traps may exist.
Both in-situ and long distance migration. |
| k. Depth ranges | San Luis Basin: 7,000 ft to 17,000 ft (Brister and Gries, 1994); Albuquerque Basin: 5,000 ft to 12,000 ft (Lozinsky, 1994). |

Production and Drilling Characteristics:	i. Pressure gradients	The Santa Fe Group of the San Luis Basin supports substantial artesian water flows. Insufficient pressure data is available for the Mesozoic section.
	a. Important fields/reservoirs	
	b. Cumulative production	
Economic Characteristics:	a. Inert gas content	Unknown at present.
	b. Recovery	
	c. Pipeline infrastructure	Gas pipeline infrastructure is non-existent to limited.
	d. Exploration maturity relative to other basins	Immature.
	e. Sediment consolidation	The Santa Fe Group is unconsolidated. The Mesozoic and Paleozoic sections are well indurated.
	f. Porosity/completion problems	There may be parts of the Albuquerque basin which are tightly cemented in the Cretaceous. Both basins are likely to have swelling clays within the Cretaceous sandstones that will need to be drilled and treated with appropriate fluids. Fracture stimulation will likely be needed to obtain commercial production.
	g. Permeability	Unknown
	h. Porosity	8-24% (Black, 1982).





Explanation

	Fault scarp
	Normal fault; U indicates upthrown block, D indicates downthrown block
	Fault; arrows indicate direction of displacement
	Intersection of Rio Grande fault with the north face of the block diagram
	Anticline, showing direction of axis
	Strike and dip direction

Figure 94. Generalized structure model of the Albuquerque Basin showing opposing structural asymmetry of the north and south halves of the basin and the controlling master normal faults. After [Russell and Snelson \(1990\)](#), and [May and Russell \(1994\)](#).

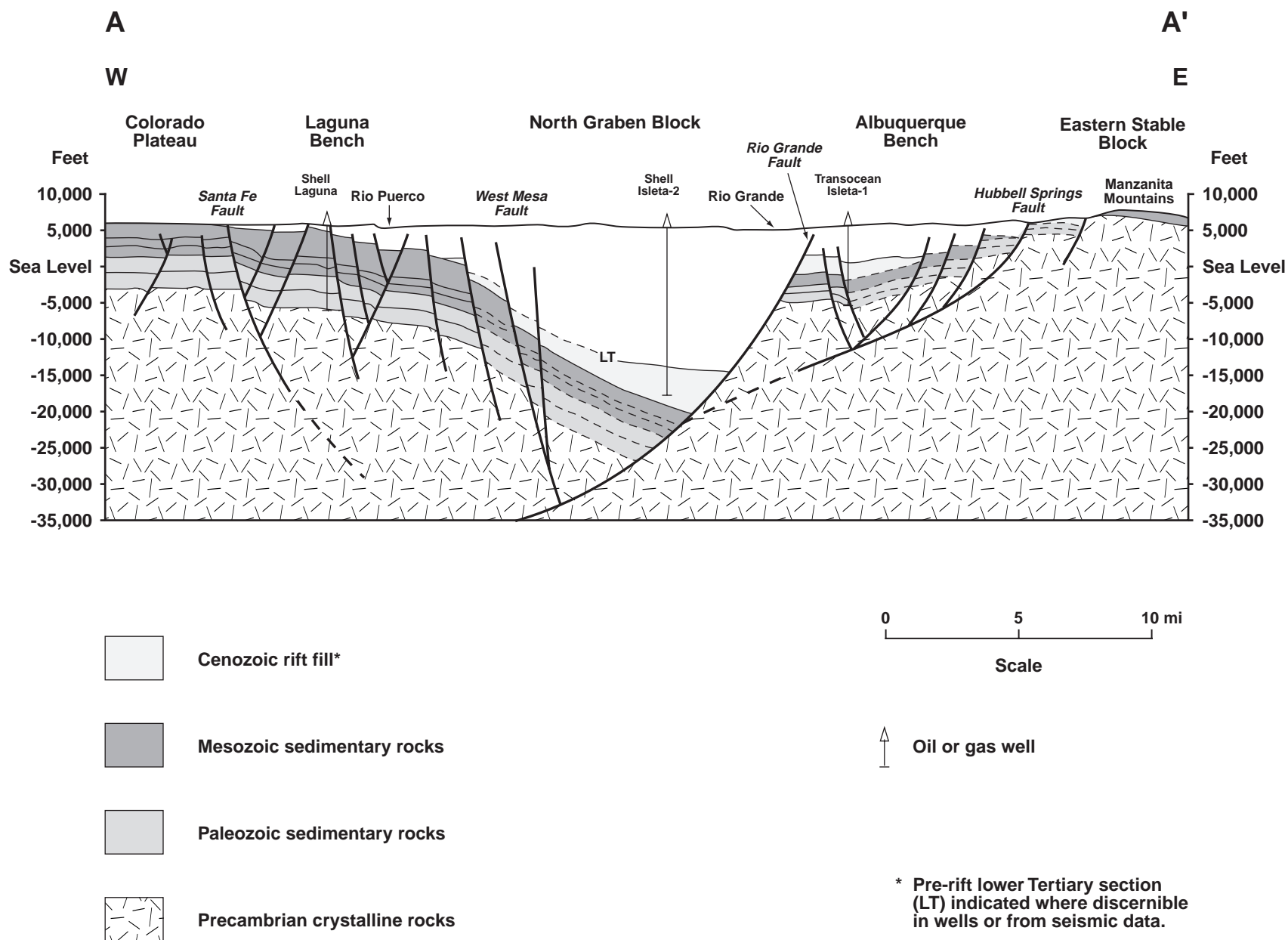


Figure 95. Cross section A- A' of the North Graben Block of the Albuquerque Basin, Rio Grande Rift zone, New Mexico. Figure 93 shows the location of the section. After Russell and Snelson (1994).

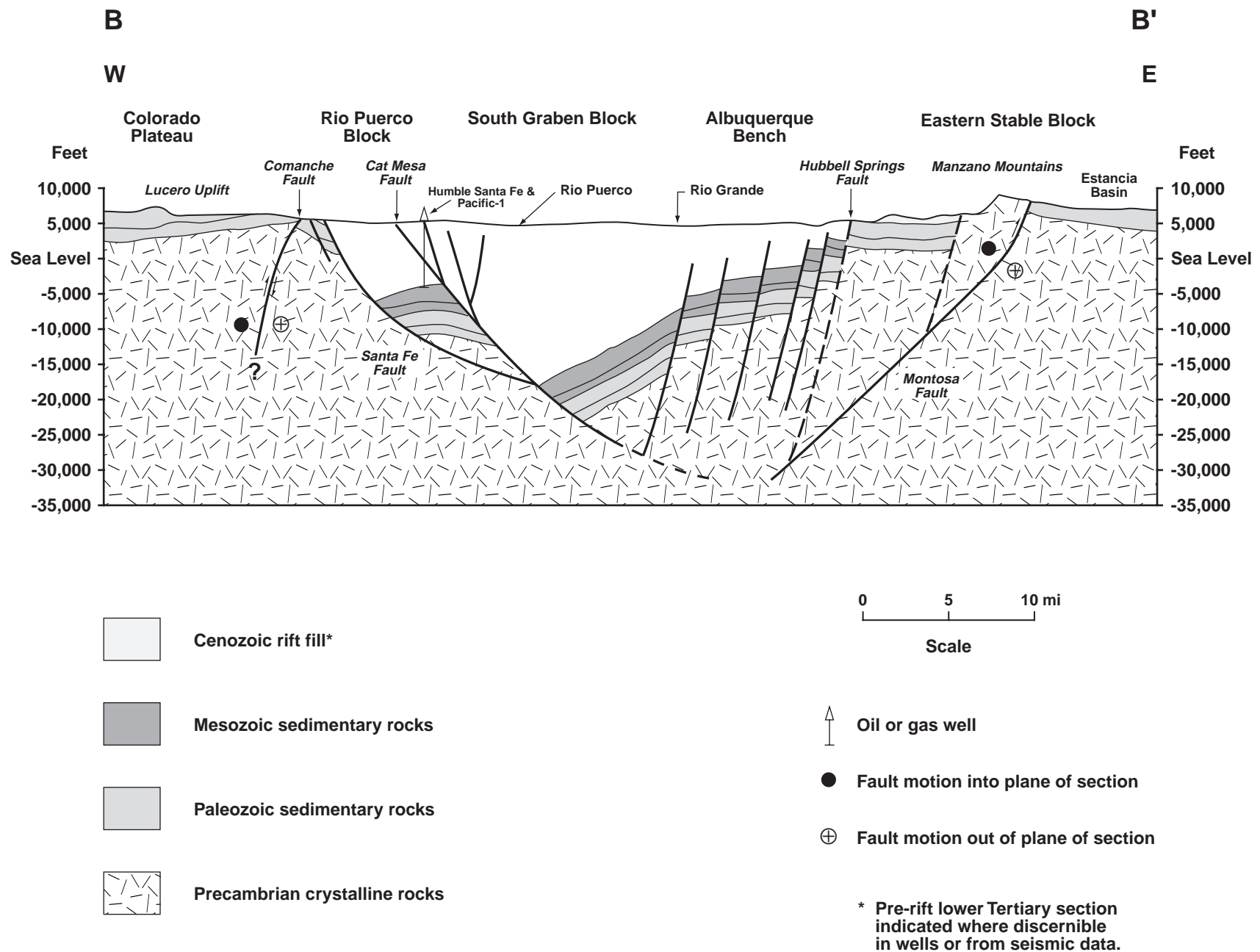


Figure 96. Cross section B-B' of the South Graben Block of the Albuquerque Basin, Rio Grande Rift zone, New Mexico. Figure 93 shows the location of the section. After [Russell and Snelson \(1994\)](#).

Age		South	Formation or Group	North
Cenozoic	Tertiary	Quaternary		
		Alluvium and undivided		
		?		
		Pliocene		
		Santa Fe Group		
		Miocene		
		Oligocene		
		Abiquiu, Picuris, or Espinazo Formation		
		Conejos Formation		
		Eocene		
		Baca Formation		
		Galisteo Formation		
		Blanco Basin Formation		
Mesozoic	Cretaceous	Menelee Formation		
		Point Lookout Sandstone		
		Dalton Sandstone Mbr.		
		Crevasse Canyon Fm		
		Tocito Sandstone lens		
		Gallup Sandstone		
		Semilla Ss Mbr.		
		Codell Ss Mbr.		
		Dakota Sandstone		
		Morrison Sandstone		
Paleozoic	Jurassic	Junction Creek Sandstone		
		Wanakah Formation		
		Todilto Limestone Member		
		Entrada Sandstone		
		Chinle Formation		
		San Andres Limestone		
		Glorieta Sandstone		
		Yeso Formation		
		Abo Formation		
		Madera Limestone		
Paleozoic	Permian	Kelly Limestone or Espiritu Santo Formation		
		Basement complex		
		Precambrian		

of Carlile Shale (eastern Colorado terminology)

~~~~~ Unconformity

Figure 97. Stratigraphic column for the Albuquerque Basin and Rio Grande Rift zone. After [Molenaar \(1996\)](#).

## SACRAMENTO BASIN

### GEOLOGIC SETTING

The present day Sacramento Basin lies within California's northwest-southeast trending Great Valley, between the Sierra Nevada Range on the east, the Coast Ranges on the west, the Klamath Mountains to the north, and the Stockton Arch on the south ([Figure 98](#)); the Stockton Arch separates the Sacramento from the adjoining San Joaquin basin.

Structural development began in late Jurassic time as a forearc basin formed between the Sierra highlands on the east and a wedge of Franciscan rock to the west. In early Cretaceous time, the basin began to fill with deep water sands and shales. By the late Cretaceous, delta-slope and turbidite fan systems dominated sedimentation, and the basin developed its characteristic asymmetry. The basin deep developed below the break in slope of the forearc's shelf.

Structural styles differ across the basin. The eastern flank exhibits high angle normal faults typical of extensional faulting of a stable shelf into an adjoining basin. Complex folding and faulting characterize the tectonically active western side. The Stockton Arch Fault developed at the close of the Cretaceous period and divided the forearc basin into the two present-day subbasins. Continued subsidence during the early Tertiary led to several cycles of marine deposits overlain by non-marine sediments. Structural deformation continued throughout the Tertiary, especially on the west sides of both basins ([Callaway and Rennie, 1991](#); [Montgomery, 1988c](#)).

The Forbes Formation is a mud-rich turbidite fan system that prograded southward along the Sacramento Basin axis ([Imperato et al., 1990](#)), and has historically had significant oil and gas development. This formation unconformably lies over the late Cretaceous Dobbins Shale, and in turn underlies the late Cretaceous Kione Delta units and Sacramento Shale ([Figure 99](#)).

### HYDROCARBON PRODUCTION

Hydrocarbons in the Forbes usually occur in discreet, lenticular stratigraphic traps or in combination structural-stratigraphic traps, where structure has concentrated gas. Traps often involve multiple fault blocks with sealing faults and can be quite complex. Productive sands have porosities of 30% and permeabilities of 100 md (millidarcies), and are usually 15 to 30 ft thick. Stacked sands often allow multiple completions in each well bore. In the northern Sacramento Basin, the Forbes generally produces to a depth of 9,000 ft. Permeability decreases with depth, so few wells have penetrated the Forbes in the deeper southern half of the basin. One now-abandoned well exceeded 11,000 ft depth, but produced only a non-commercial 0.12 BCFG ([Callaway and Rennie, 1991](#); [Montgomery, 1988c](#); [Weagant, 1972, 1986](#); and [Ziegler and Spotts, 1978](#)).

Overpressure often occurs in the Forbes Formation, and pressure gradients rise as high as 0.8 to 9 psi/ft below 6,000 ft depth ([Lico and Kharaka, 1983](#)). In some cases, changes in pressure gradients may correlate with hydrodynamic gradients or the post-depositional emplacement of magmatic stocks. Overpressure along the west flank of the Sacramento and San Joaquin basins may have some relation to structural compression associated with Mesozoic subduction and more recent plate movements ([Montgomery, 1988c](#); and [Weagant, 1972, 1986](#)).

Shales of the Dobbins, the Sacramento and the Forbes formations are likely gas sources. Cretaceous shales of the Sacramento and northern San Joaquin basins generally contain less than 1.0% total organic content (TOC). The organic material is largely humic or non-sapropelic and therefore gas prone. Gas generation in Cretaceous rocks probably began at burial depths of 13,000 to 15,000 ft ([Figure 100](#)). The "Delta depocenter" in the southern Sacramento Basin was probably the major source for gas in this basin and for the gas fields in the northern San Joaquin ([Ziegler and Spotts, 1978](#); [Callaway and Rennie, 1991](#)).

## EVIDENCE FOR BASIN-CENTERED GAS

The northern Sacramento Basin is a dry-gas province, and the Forbes is a major conventional producer in the basin. While the overlying Cretaceous Kione and Tertiary sands are also important producers, the Forbes will most likely host a basin-centered accumulation. Evidence for such accumulations in the basin include the following:

- 1) Cretaceous shales of the Dobbins and Forbes formations are mature in the deepest parts of the Sacramento Basin, especially in the Delta depocenter ([Ziegler and Spotts, 1978](#)).
- 2) The turbidite fan nature of the Forbes ensures reservoirs encasement within the source shales ([Weagant, 1972, 1986](#); [Montgomery, 1988c](#)).
- 3) Overpressuring occurs in the Forbes, although hydrodynamics and post-depositional structural movement complicate pressure distribution in the formation. A better understanding of pressure distribution in the Forbes, especially in the deeper Sacramento Basin would aid in evaluating the potential for the preservation of reservoir permeability at depth. ([Weagant, 1972, 1986](#); [Montgomery, 1988c](#)).

## KEY ACCUMULATION PARAMETERS

### Identification

Pacific Coast, Sacramento and San Joaquin Basins, Forbes formation

### Geologic Characterization of Accumulation:

- a. Source/reservoir** Dobbins and Sacramento shales and shales of the Forbes Formation; reservoirs are turbidite sands of the Forbes ([Callaway and Rennie, 1991](#); [Ziegler and Spotts, 1978](#); [Magoon et al., 1996](#); [Weagant, 1972, 1986](#)).
- b. Total Organic Carbons (TOCs)** Less than 1.0% ([Ziegler and Spotts, 1978](#)).
- c. Thermal maturity** Cretaceous shales are gas mature below 13,000 ft ([Ziegler and Spotts, 1978](#)).
- d. Oil or gas prone** Gas prone ([Ziegler and Spotts, 1978](#)).
- e. Overall basin maturity** Basin normally mature; Tertiary generally not mature.
- f. Age and lithologies** Late Cretaceous shales and sands.
- g. Rock extent/quality** Forbes Fm present throughout Sacramento Basin; Forbes present in northern half of San Joaquin Basin. Reservoir rocks are discontinuous and are distributed vertically throughout formation.
- h. Potential reservoirs** Conventional production from Forbes; non-conventional, basin centered production not established.
- i. Major traps/seals** Stratigraphic and combination structural-stratigraphic traps are common. Seals include encasing shales and sealing faults.
- j. Petroleum generation/migration models** Onset of gas generation at burial depths of 13,000 ft; migration to conventional traps over distances of 60-100 mi ([Ziegler and Spotts, 1978](#); [Magoon et al., 1996b](#)).
- k. Depth ranges** Production from conventional reservoirs at depths of 4000 to 9000 ft; deepest completion 11,064-11,144 ft ([California Division of Oil, Gas and Geothermal Resources, 1997](#)).
- l. Pressure gradients** Overpressure often occurs in Forbes Fm; gradients range from 0.8 to 9 psi/ft below 6,000 ft depth ([Lico and Kharaka, 1983](#)).

**Production and Drilling  
Characteristics:**

- |                                       |                                                                                                                                                                    |
|---------------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <b>a. Important fields/reservoirs</b> | Rice Creek, Tisdale, Grimes, and Arbuckle fields ( <a href="#">California Division of Oil, Gas and Geothermal Resources, 1997</a> ).                               |
| <b>b. Cumulative production</b>       | Rice Creek, 35 BCFG; Tisdale, 45 BCFG; Grimes, 619 BCFG; and Arbuckle, 78 BCFG ( <a href="#">California Division of Oil, Gas and Geothermal Resources, 1997</a> ). |

**Economic  
Characteristics:**

- |                                                         |                                                                                                                                                                                                                                                                                       |
|---------------------------------------------------------|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <b>a. Inert gas content</b>                             | Nitrogen is common in the Sacramento Basin; gases are blended to reach commercial BTU levels.                                                                                                                                                                                         |
| <b>b. Recovery</b>                                      | Forbes is currently regarded as a conventional play and operators are reluctant to compete zones that appear to have low deliverability/recovery.                                                                                                                                     |
| <b>c. Pipeline infrastructure</b>                       | Good to excellent.                                                                                                                                                                                                                                                                    |
| <b>d. Exploration maturity relative to other basins</b> | Mature.                                                                                                                                                                                                                                                                               |
| <b>e. Sediment consolidation</b>                        | Normal consolidation with depth.                                                                                                                                                                                                                                                      |
| <b>f. Porosity/completion problems</b>                  | Forbes is currently regarded as a conventional play, and operators complete sands with 10% or greater porosities. Overpressure conditions occur throughout the play, but are often related to local structural conditions ( <a href="#">Weagant, 1972, 1986; Montgomery, 1988c</a> ). |
| <b>g. Permeability</b>                                  |                                                                                                                                                                                                                                                                                       |
| <b>h. Porosity</b>                                      |                                                                                                                                                                                                                                                                                       |

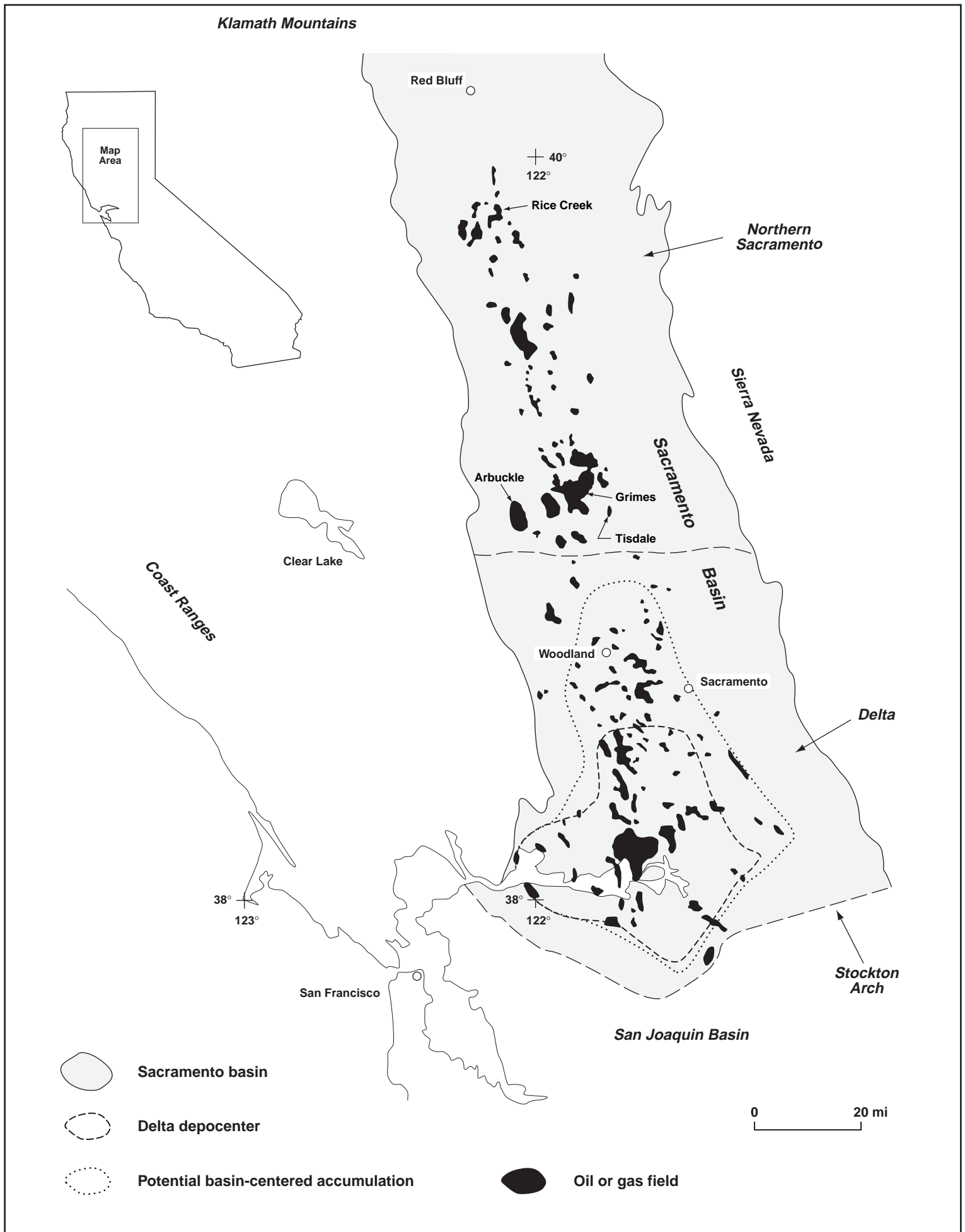


Figure 98. Index map of the Sacramento basin and inclusive oil and gas fields, California. After [California Division of Oil, Gas, and Geothermal Resources W6-1, 2 \(1999\)](#).

| Series              | Unit                      |
|---------------------|---------------------------|
| Upper<br>Cretaceous | Mokelumne River Formation |
|                     | HT Shale                  |
|                     | Tracy Fm                  |
|                     | Starkey Formation         |
|                     | Winters Formation         |
|                     | Sacramento Shale          |
|                     | Kione Formation           |
|                     | Forbes Formation          |
|                     | Dobbins Shale             |
|                     | Guinda Fm                 |
|                     | Funks Fm                  |
|                     | Sites Fm                  |
|                     | Yolo Fm                   |

Figure 99. Stratigraphic column for the Sacramento Basin, California. After [Montgomery \(1988c\)](#).

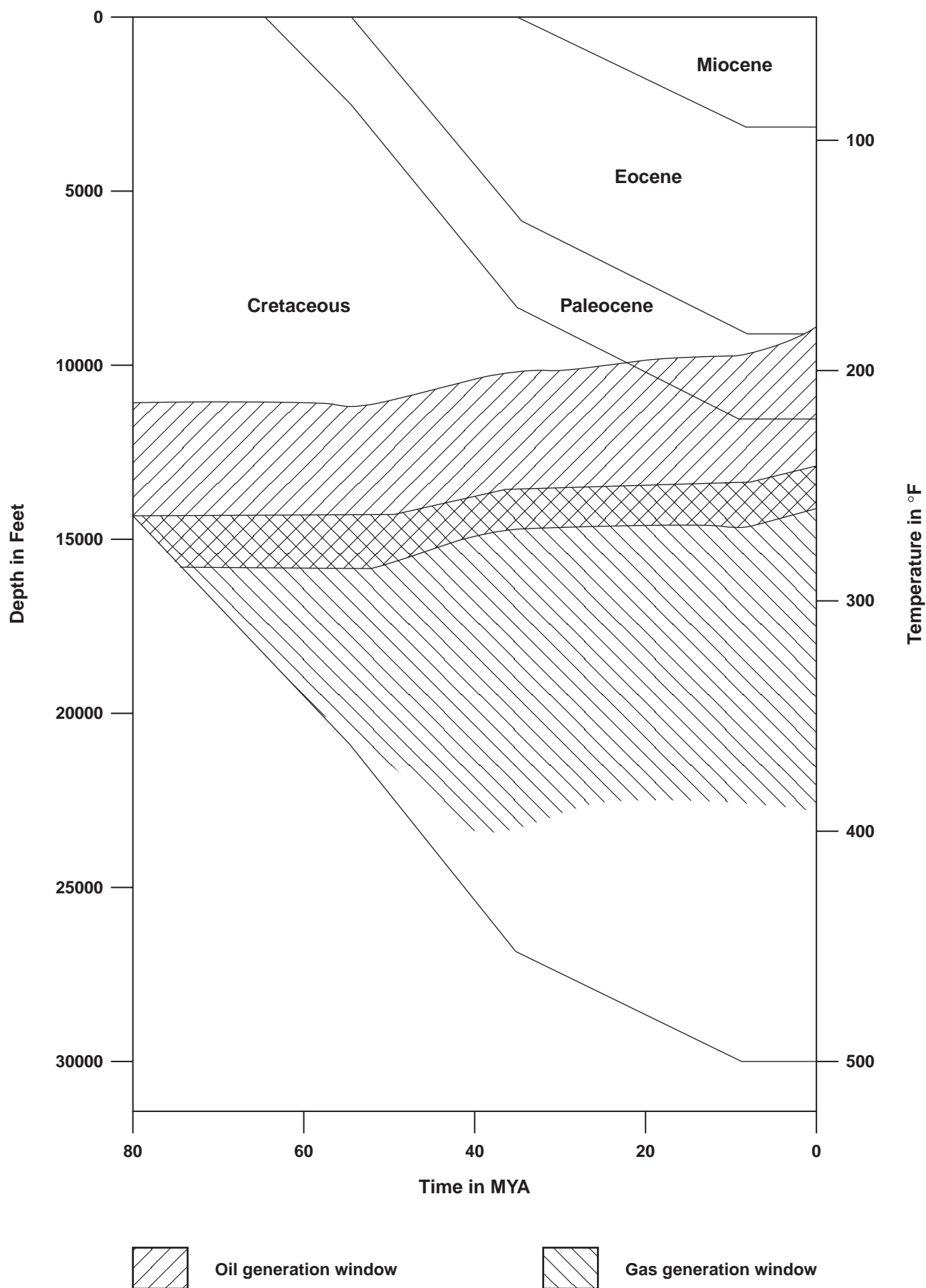


Figure 100. Lopatin diagram showing stratigraphic reconstructions and oil and gas generation windows for the thickest part of the Delta depocenter, Sacramento basin, California. After [Ziegler and Spotts \(1978\)](#).

## **SALTON TROUGH, CALIFORNIA**

### **GEOLOGIC SETTING**

The Salton Trough is an active rift basin lying within the Imperial Valley at the northern end of the Gulf of California (Figure 101). The basin extends about 115 miles in length and 45 miles in width, and encompasses an area of 4,500 square miles (Barker, 1996b). The rift apparently contains metamorphosed sediments, igneous intrusions and rising upper mantle material (Figure 102). The transfer zones between the major strike-slip faults may have active rhombic-shaped spreading centers, especially at the southern end of the Salton Sea and at Cerro Prieto (Figure 101) (Lonsdale, 1989; and Mueller and Rockwell, 1991).

Paleogeographic reconstructions show that the Gulf of California opened during middle Miocene time and reached its maximum northward extent in the early Pliocene (Smith, 1991). Deltaic and lacustrine sediments from the Colorado River filled the northern end of the Gulf of California beginning 5.5 Ma, eventually cutting it off from the marine seaway by 4 Ma (Schmidt, 1990). The basin now contains 16,000 to 20,000 ft of sediments and metasediments, including Miocene to Pliocene-age evaporites, marine and continental deposits, and a thick section of Pleistocene to Recent deltaic and lacustrine sediments (Helgeson, 1968; Muffler and Doe, 1968). Figure 103 shows a general stratigraphic column for the Salton Trough (Muffler and Doe, 1968; Lucchitta, 1972). Dibblee (1984), Gibson et al. (1984), and Kerr and Kidwell (1991) have described the sedimentary formations exposed in outcrops along the western and eastern flanks of the Salton Trough. Mesozoic igneous and metamorphic rocks form the base of the exposed section. Above this crystalline basement are alluvial fans and breccias of the Miocene Anza and Split Mountain Formations. Interfingered with the Split Mountain is the Fish Creek Gypsum, a formation of gypsum and anhydrite that indicates rift basin development began in middle Miocene time. Breccias and marine turbidites overlie the evaporite beds and indicate rapid subsidence. The turbidites grade upward and laterally into shallow marine shoreline deposits of the Pliocene Imperial Formation. These are overlain by deltaic and lacustrine sediments deposited by the Colorado River. This basin has continued to subside, and recent erosion has not removed any sediments.

Active strike-slip motion complicates the rift basin geology within the San Andreas, Imperial and Cerro Prieto fault zones. Calculated slip rates for the various strike-slip faults in the Salton Trough range from 1.7 to 5.4 cm/year (Duffield, 1976; Suarez-Vidal et al., 1991). According to Elders (1979), the Salton Trough is one of the most earthquake-prone areas in North America. The basin undergoes active deformation, as indicated by movements observed from tiltmeter and survey data. Lippmann and Manon (1987) described earthquake activity along the Imperial and Cerro Prieto fault zones near Cerro Prieto geothermal field. Such seismic activity can potentially disrupt or breach hydrocarbon traps and pressure seals, preventing accumulation of hydrocarbons.

### **HYDROCARBON PRODUCTION**

To date, the Salton Trough has no recorded hydrocarbon production.

## EVIDENCE FOR BASIN-CENTERED GAS

According to gas sample data from geothermal wells and fumaroles, the main gas expelled in the basin is CO<sub>2</sub>. Most samples show 80 to 90 wt % CO<sub>2</sub> and only 3 to 5 wt% of hydrocarbon gases (Nehring and D'Amore, 1981; 1984). For many years a dry-ice factory produced CO<sub>2</sub> from shallow wells near the Salton Sea.

Thermal gradients and maturity levels vary throughout the basin. In cooler areas, conditions may favor generation and expulsion of natural gas. However, Colorado River sediments apparently lack hydrocarbon source material. Analyses of deep-well cuttings show small amounts (< 0.5 wt%) of total organic carbon (TOC). The only potential source rocks noted in the geologic literature have been minute coal fragments: Nehring and D'Amore (1981, 1984) reported dispersed lignite particles in deltaic sediments from a deep well (Prian #1) near Cerro Pietro. This coaly material may possibly generate the small amounts of hydrocarbon gases found in Cerro Pietro geothermal wells. Published lithology logs and formation descriptions include no coal beds or swamp environments in the sedimentary section, so the origin, extent and depositional trend of the carbonaceous units remain unknown. The lignite fragments in the Prian #1 well may represent allocthonous deposition of Cretaceous coal eroded from the Colorado Plateau.

Vitrinite reflectance (R<sub>o</sub>) measurements for several areas in the Salton Trough indicate high thermal maturation. Barker (1996b) reported an R<sub>o</sub> of 3% at 13,400 ft in the Chevron Wilson #1 well (20-T14S-R15E). Drilled within a relatively cool part of the basin, this well had a temperature gradient of only 60 ° C/km.

Figure 104 shows a plot of vitrinite reflectance versus depth for several wells at the Cerro Prieto geothermal field (Barker and Elders, 1981). The graph displays considerable variability in vitrinite gradients that probably depends on proximity to a “hot spot.” Some wells show R<sub>o</sub> ranges from 0.7 to 1.0% at depths as shallow as 800 to 3,300 ft. In borehole M-84, vitrinite reflectance ranges from 0.12% at 790 ft to 4.1% at 5,580 ft (Barker and Elders, 1981). These data indicate that thermal maturation levels have reached or exceeded the wet-gas floor and dry-gas preservation limit (Dow, 1977) at very shallow depths in the hot spots.

Although under-explored parts of the basin may contain undiscovered coal seams or lacustrine shale beds with high organic content, the data apparently indicate “normal” pressures at depth throughout the section, and observations lead to the conclusion that water has entirely saturated potential reservoir rocks. Thus, all the data indicate the Salton Trough probably contains no basin-centered gas accumulation.

## KEY ACCUMULATION PARAMETERS

### Identification

Pacific Coast Province, Salton Trough, Imperial Valley, normally pressured, hydrogeothermal basin.

### Geologic Characterization of Accumulation:

- |                                                 |                                                                                                                                                                                                                                                                      |
|-------------------------------------------------|----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <b>a. Source/reservoir</b>                      | Remote possibilities in the lacustrine shale beds (Miocene through Recent) and dispersed coaly beds (Colorado River Recent sediments)                                                                                                                                |
| <b>b. Total Organic Carbons (TOCs)</b>          | 0.09% (Palm Spring Formation (Plio-Pleistocene)), 0.2% (Pliocene lacustrine and deltaic sediments), and 15 samples from the Cal State 2-14 (14-T11S-R13E) well were less than 0.4 % TOC ( <a href="#">Barker and Elders, 1981</a> ; <a href="#">Barker, 1996b</a> ). |
| <b>c. Thermal maturity</b>                      | $R_o = 0.7$ to 4.1 at depths from 3280-5576 ft ( <a href="#">Barker and Elders, 1981</a> ).                                                                                                                                                                          |
| <b>d. Oil or gas prone</b>                      | Gas ( $CO_2$ is common; very minor concentrations of hydrocarbon gases).                                                                                                                                                                                             |
| <b>e. Overall basin maturity</b>                | Very high level of maturation due to post-Miocene hydrogeothermal activity.                                                                                                                                                                                          |
| <b>f. Age and lithologies</b>                   | Miocene to Recent breccias, turbidites, deltaic and lacustrine deposits                                                                                                                                                                                              |
| <b>g. Rock extent/quality</b>                   | Source rocks generally lacking, highly variable levels of induration throughout the stratigraphic section due to hydrothermal activity.                                                                                                                              |
| <b>h. Potential reservoirs</b>                  | Colorado River deltaic and lacustrine (Recent) sediments.                                                                                                                                                                                                            |
| <b>i. Major traps/seals</b>                     | If not compromised by faulting, hydrothermal mineralization throughout the stratigraphic section, Pliocene lacustrine deposits, and Miocene Fish Creek gypsum and anhydrites.                                                                                        |
| <b>j. Petroleum generation/migration models</b> | In-situ generation of dispersed coally material within the Colorado River deltaic sediments is a remote possibility; other source rocks are lacking.                                                                                                                 |
| <b>k. Depth ranges</b>                          | Sediment fill of up to 20,000 ft.                                                                                                                                                                                                                                    |
| <b>l. Pressure gradients</b>                    | Wells drilled at the Salton Sea and Cerro Prieto geothermal fields had gradients that ranged from 0.40 to 0.42 psi per ft ( <a href="#">Muffler and White, 1969</a> ; <a href="#">Bermejo et al., 1981</a> ).                                                        |

**Production and Drilling  
Characteristics:**

- |                                       |      |
|---------------------------------------|------|
| <b>a. Important fields/reservoirs</b> | none |
| <b>b. Cumulative production</b>       | none |

**Economic  
Characteristics:**

- |                                                         |                                                                                                                                                                 |
|---------------------------------------------------------|-----------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <b>a. Inert gas content</b>                             | High CO <sub>2</sub> (80 to 90 wt%).                                                                                                                            |
| <b>b. Recovery</b>                                      |                                                                                                                                                                 |
| <b>c. Pipeline infrastructure</b>                       | poor                                                                                                                                                            |
| <b>d. Exploration maturity relative to other basins</b> |                                                                                                                                                                 |
| <b>e. Sediment consolidation</b>                        | Poorly consolidated sediments, except in the vicinity of geothermal anomalies where hydrothermal fluids have effectively cemented thousands of feet of section. |
| <b>f. Porosity/completion problems</b>                  | Sediments deposited are mineralogically complex with a variety of clays; also problematic are well indurated rocks in geothermal areas.                         |
| <b>g. Permeability</b>                                  |                                                                                                                                                                 |
| <b>h. Porosity</b>                                      |                                                                                                                                                                 |

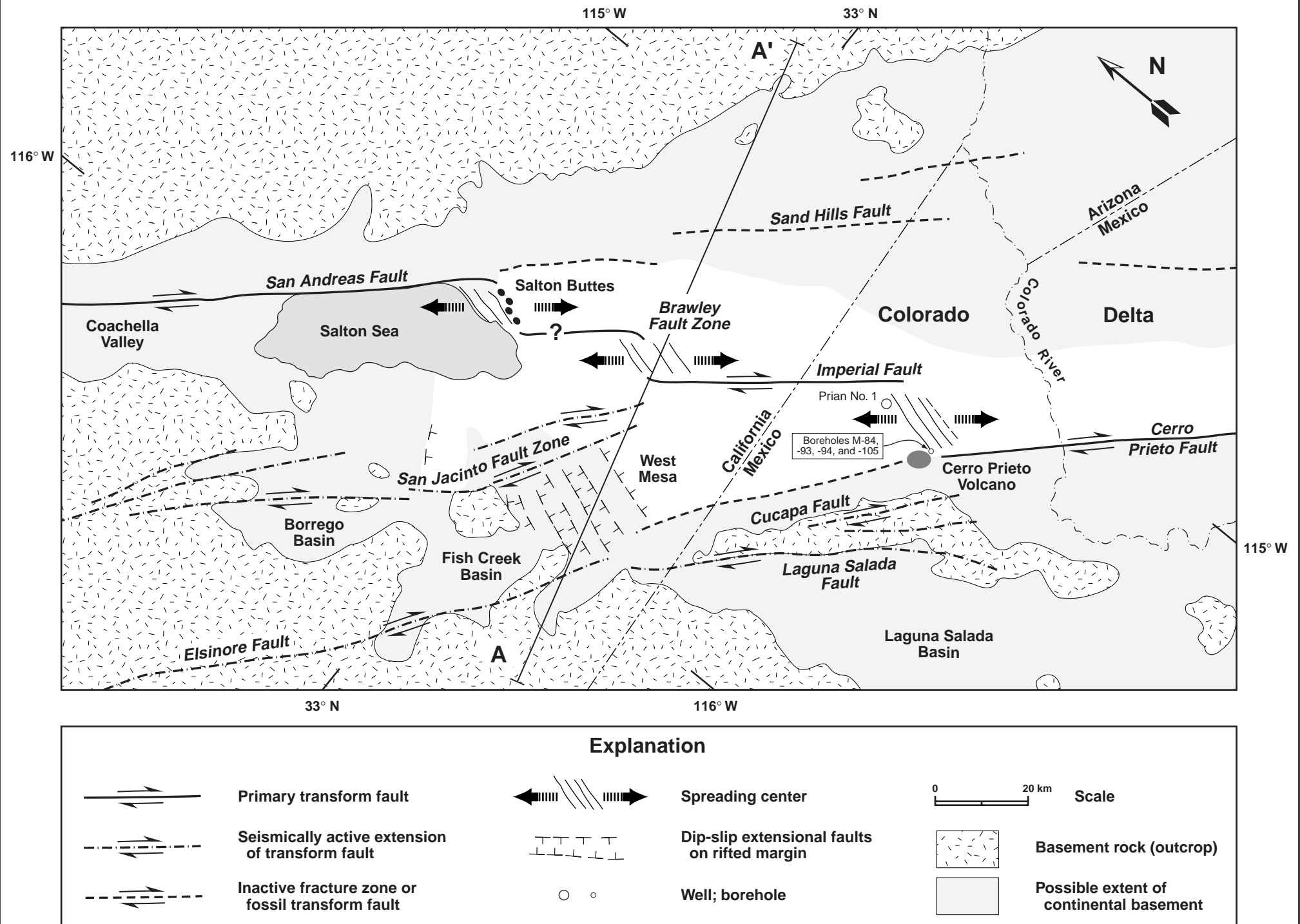


Figure 101. Geologic map of Salton Trough in southern California. After [Lonsdale \(1989\)](#).

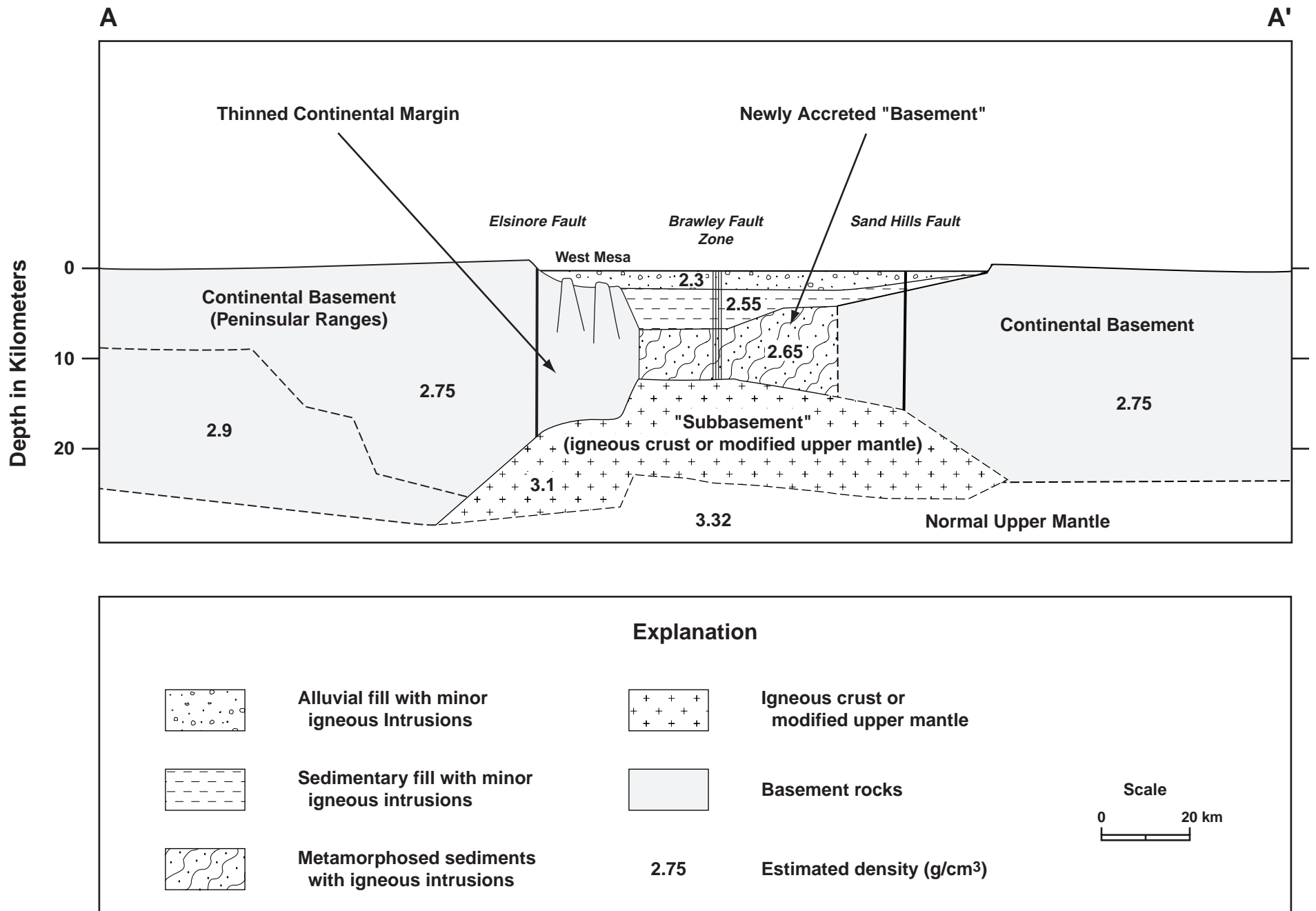


Figure 102. Cross section of Salton Trough in southern California. Dashed boundaries are controlled by gravity modeling only. After [Fuis et al. \(1982\)](#) and [Lonsdale \(1989\)](#).

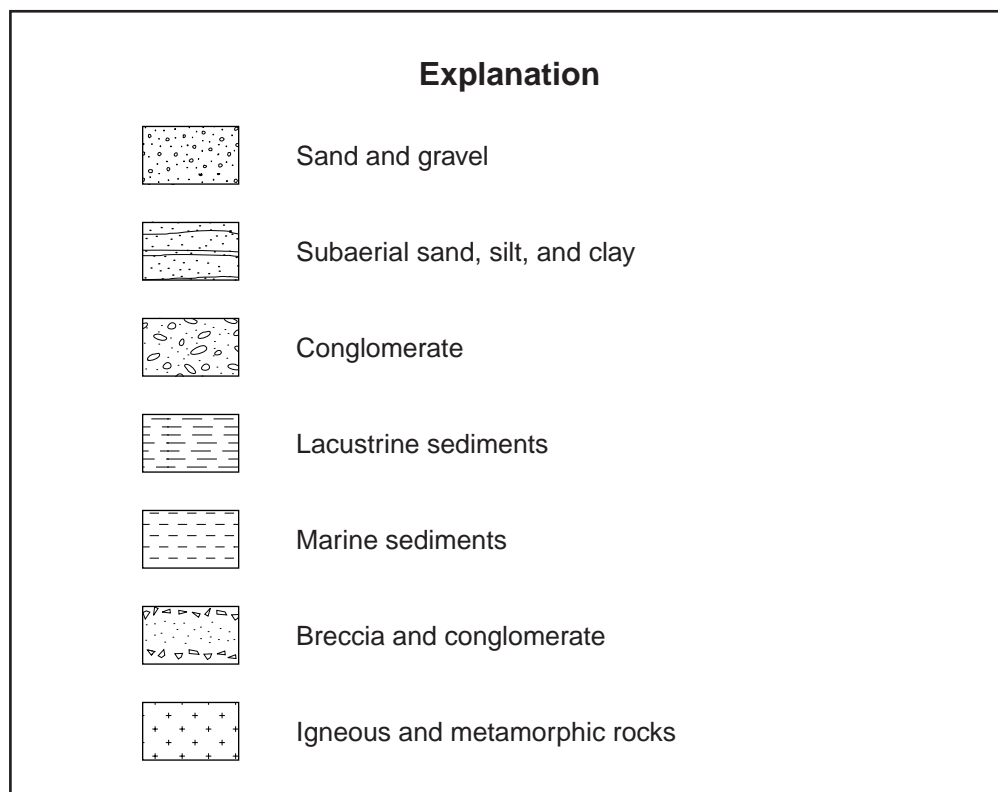
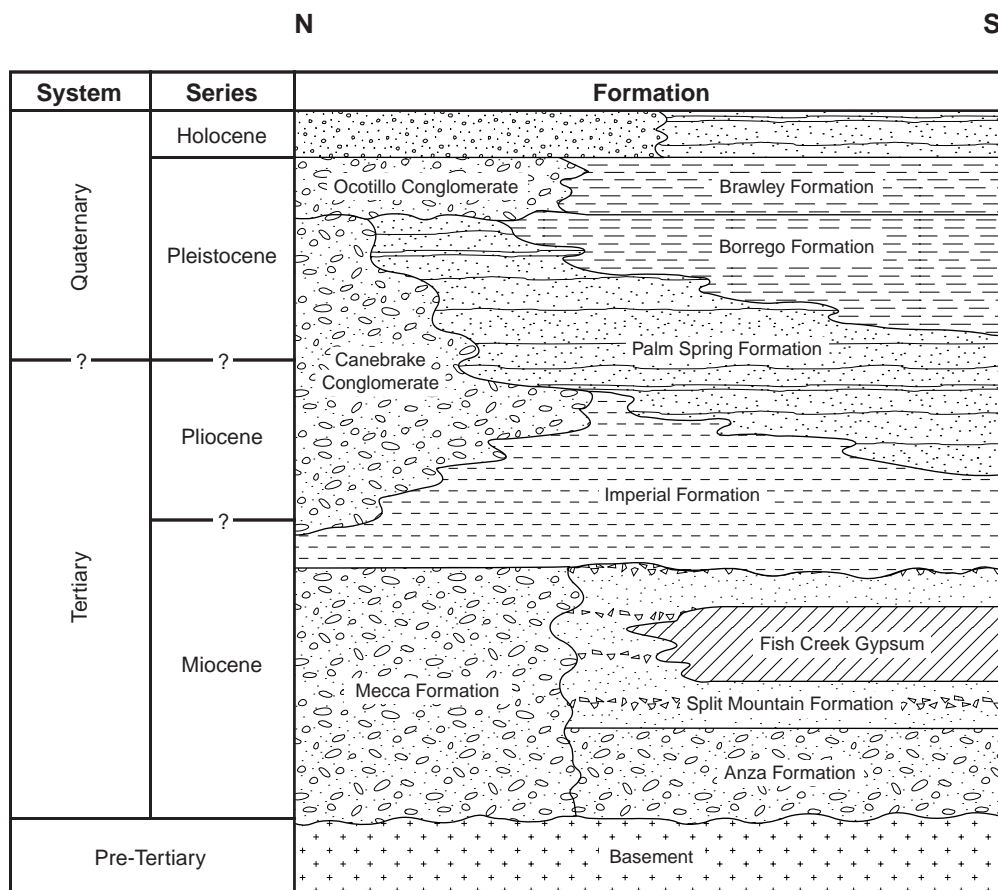


Figure 103. Generalized stratigraphy of the Salton Trough. After [Muffler and Doe \(1968\)](#), and [Lucchitta \(1972\)](#).

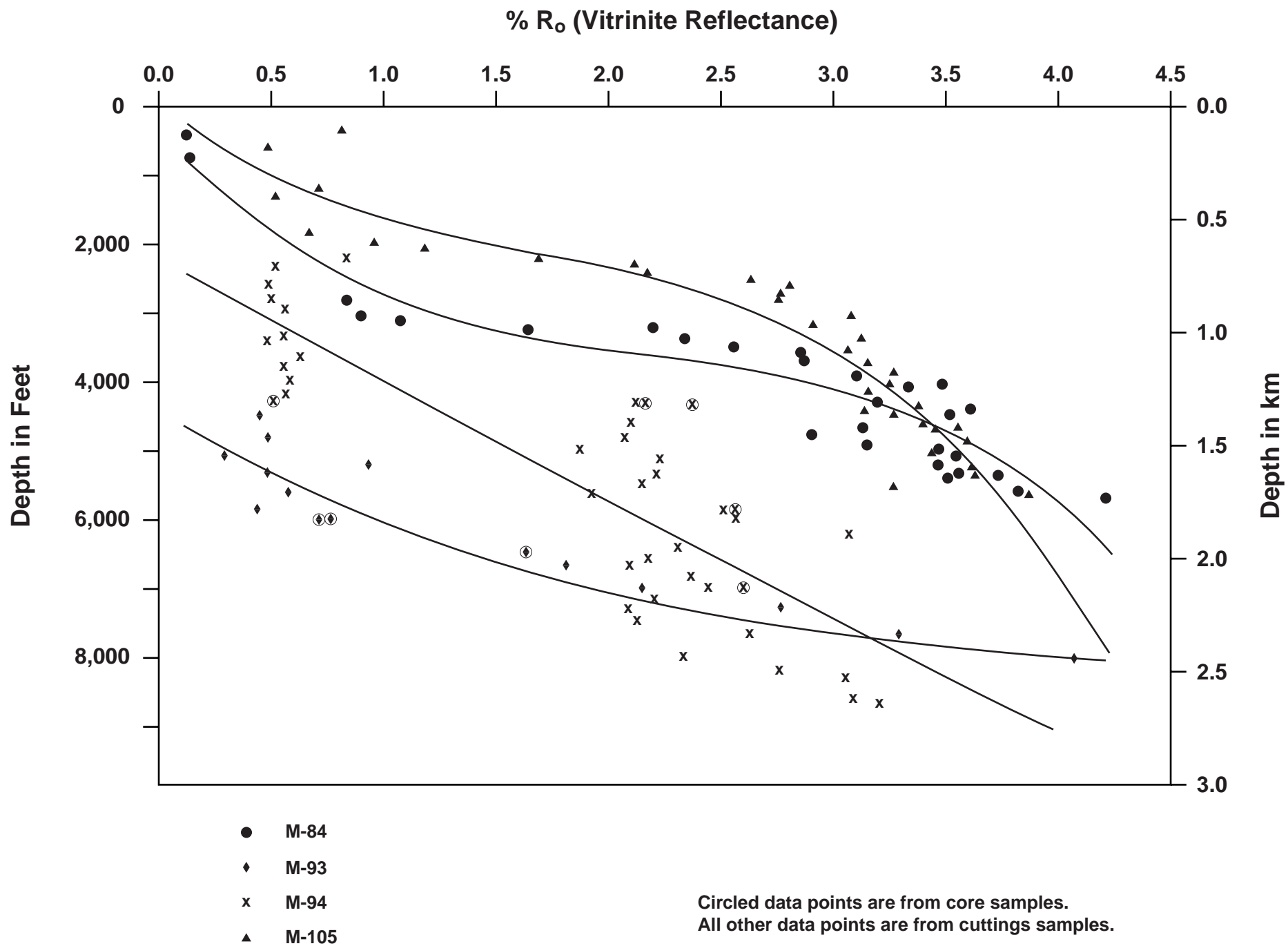


Figure 104. Average vitrinite reflectance as a function of sample depth in boreholes M-84, M-93, M-94, and M-105 near the Laguna Salada fault zone (see [Figure 101](#)). Third-order polynomial regression curves plotted for M-84, M-93, and M-105 indicate the rank profile. After [Barker and Elders \(1981\)](#).

## SAN RAFAEL SWELL (DAKOTA FORMATION)

### GEOLOGIC SETTING

The San Rafael Swell is an uplift located on the northwest side of the Paradox Basin in north-central Utah (Figure 105). Two sub-parallel rows of southward-facing cliffs, the Book Cliffs and the Roan Cliffs, rim the Swell on the northeast, and the high-plateau volcanic area near Richfield forms the southwest border. Rocks in the San Rafael Swell range in age from Permian through Cretaceous, with Eocene strata exposed to the north as the Swell merges with the south limb of the Uinta Basin (Figure 106). Maximum thickness of Phanerozoic sediments on the Swell ranges from 5,000 to 8,000 feet.

The Lower Cretaceous in this area includes the Cedar Mountain Formation (Albian), unconformably overlain by the Dakota Sandstone (Cenomanian), which is in turn unconformably overlain by the Tununk Member of the Mancos Shale (Turonian) (Young, 1960). The Dakota Sandstone and Cedar Mountain Formation comprise the Dakota Group. Spieker (1946) designated the entire Cretaceous interval as the Indianola Group (Figure 107).

The Dakota Group rocks derive from formations uplifted and thrust eastward during the Sevier orogeny (Lawton, 1983, 1985; Peterson, 1994a). Deposition occurred along the western shore of a Cretaceous seaway that traversed the continent from Mexico to the Arctic. Dakota sediments unconformably onlap the Morrison Formation on the west and grade eastward into a marine shale (Figure 107) (McGookey et al., 1972). The Dakota Group represents four major stratigraphic sequences which reflect regional base-level fluctuations caused by both tectonics and eustatic sea level changes. Multiple unconformities and smaller-scale sequences occur within each megasequence, in response to variations in sediment supply, climatic fluctuations and local structural developments (Dolson and Muller, 1994). Elder and Kirkland (1964) present a relative sea-level curve and ammonite zonation for the Cenomanian of central Utah.

Peterson (1969) subdivided the Dakota Formation into three lithic units: a lower conglomeratic sandstone and shale unit from 0 to 65 ft thick; a middle carbonaceous shale, coal and sandstone unit from 0 to 80 ft thick; and an upper marine sandstone unit from 0 to 85 ft thick. The upper unit contains a large and diverse marine molluscan faunal assemblage, consisting mostly of bivalves and ammonites (Eaton et al., 1990). Sandstones in the Dakota generally thicken and coarsen westward.

The San Rafael Swell resulted from basement uplift and thin-skinned deformation, where the eastward-verging Sevier orogenic belt impinged on the nearly horizontal strata of the Colorado Plateau. Exposures on the west flank of the Swell show detachment folds occur above a décollement in the Jurassic Carmel Formation, where a fold train lies above a thin gypsum layer. These folds developed in response to regional horizontal compression on the west limb of the Swell during Paleocene time (Royse, 1996). This décollement represents part of a stratigraphically-controlled regional detachment that occupies the east flank of the Jurassic evaporite basin.

The Swell first became active as a region of reduced subsidence before it developed topographic relief. It began to grow in mid-Cretaceous time (about 90 Ma) as a low-relief structural welt in the Rocky Mountain foreland (Perry and Flores, 1997). Giuseppe and Heller (1996) compared sections of the Price River Formation (Campanian) to the laterally equivalent Farrer Formation and found variations across the swell crest, demonstrating tectonic uplift in Late Cretaceous time.

## HYDROCARBON POTENTIAL

In central Utah very little exploration has occurred for Permian, Triassic and Cretaceous reservoirs. The flanks of the north end of the San Rafael Swell and the Circle Cliffs uplift represent prospective areas for both structural and stratigraphic traps (Sprinkel et al., 1997). Known petroleum resources of the area include gas in the Triassic Moenkopi Formation, the Cretaceous Ferron and Dakota Sandstones, and the Eocene Wasatch and Green River Formations (Figure 106). The Dakota Sandstone and Moenkopi Formation also contain small quantities of oil. Tar sands are common in the Moenkopi, and oil shale occurs in the Green River Formation. Weiss et al. (1990), and Bishop and Tripp (1993) reported extraction of some tar sands for local use, but the oil shale remains unexploited.

Dakota Group rocks have yielded more than 2.0 BBOE of hydrocarbons, mostly from stratigraphic traps controlled by paleotopography (Dolson and Muller, 1994). The Moenkopi has produced significant quantities of oil from the Grassy Trail Creek field in the Swell.

Nine gas fields exist in the area, in addition to Farnham Dome (carbon dioxide production) and Woodside Dome (helium reserves) (Production table, Key Accumulation Parameters). Two fields, the Flat Canyon and Joe's Valley, have produced natural gas from Dakota Formation reservoirs in the Wasatch Plateau adjacent to the San Rafael Swell. Dakota production may also have occurred from the abandoned Miller Creek field near Price, Utah; this field is located on the northwest plunge of the Swell.

## EVIDENCE FOR BASIN-CENTERED GAS

The Dakota Sandstone in the area north of the San Rafael swell exhibits some characteristics indicative of a basin centered gas accumulation; however, overall evidence suggests that it probably is not. The Dakota contains coal and carbonaceous shale, which are good source rocks for gas. Additionally, the thermal maturity of these source rocks is adequate for thermogenic gas generation, especially where the Dakota becomes more deeply buried in the Uinta-Piceance basin. Factors that do not favor the presence of a basin-centered accumulation include the following:

- 1) most fields are associated with structures, and
- 2) the limited production in the area looks to be conventional (i.e. reservoirs contain gas-water contacts).

## KEY ACCUMULATION PARAMETERS

### Identification

Provinces: Paradox Basin, and Uinta-Piceance Basin. Plays: Cretaceous Dakota to Jurassic; Wasatch Plateau-Emery (unconventional-coal bed gas); Permo-Triassic Unconformity; and

Cretaceous Sandstones; Accumulation: North end, San Rafael Swell

### Geologic Characterization of Accumulation:

- a. **Source/reservoir**      Organic-rich mudstones in the Mancos Shale and Cretaceous-age coals (Dakota Group, Ferron and Mesaverde formations) are the source rocks. The Ferron and Dakota sandstones are possible reservoirs for gas. Organic-rich shale of the the Permian Phosphoria and/or Park City formations may be a source of oil ([Meissner and Clayton, 1984](#)).
- b. **Total Organic Carbons (TOCs)**
- c. **Thermal maturity**      Type III Kerogen. Mean  $R_o$  ranged from 0.50 to 0.65 for coal and shale in the Dakota Sandstone ([Nuccio and Johnson, 1988](#)).
- d. **Oil or gas prone**
- e. **Overall basin maturity**
- f. **Age and lithologies**      Permian through Cretaceous in the basin area; Eocene strata exposed to north where San Rafael Swell merges with south limb of Uinta Basin. Conglomeratic sandstone, shale, carbonaceous shales, coal, and fossiliferous marine sandstones.
- g. **Rock extent/quality**      possibly basin-wide source and reservoir-rock distribution; flanks of San Rafael Swell and Circle Cliffs uplift are prospective areas for structural and stratigraphic traps ([Sprinkel et al., 1997](#)).
- h. **Potential reservoirs**      Triassic Moenkopi Formation, Cretaceous Ferron and Dakota Sandstones, and Eocene Wasatch and Green River Formations.
- i. **Major traps/seals**      Structurally controlled (simple doubly-plunging folds and complexly faulted anticlines); probably stratigraphic, with discontinuous sandstones in the Dakota and Ferron units.
- j. **Petroleum generation/migration models**      Fractures in Jurassic Entrada Sandstone on the Swell acted as conduits for hydrocarbon migration, and both solid bitumen and live oil droplets occur in lamproite dikes and secondary calcite veins which now fill the fractures; a discontinuous corridor of sub-parallel faults extends updip from these dikes towards a large tar sand deposit southeast ([Hulen et al., 1998](#)).
- k. **Depth ranges**
- l. **Pressure gradients**

**Production and Drilling  
Characteristics:**

- a. Important fields/reservoirs** Farnham Dome, Gordon Creek, Grassy Trail Creek, South Last Chance, Woodside Dome, Flat Canyon, Joe's Valley, Drunkards Wash, Peters Point, and Stone Cabin
- b. Cumulative production** See table below. As of 1998, the status for wells/fields are as follows:  
Farnham Dome, 12-15S-11E, Navajo Ss-abandoned; Gordon Creek, 8-14S-7E, Permo-Triassic rx-shut in; Woodside Dome, T19S, R13E, Permian Kaibab-shut in; Last Chance, South, T26S, R7E, Permo-Triassic rx-shut in; and Joe's Valley, T15S, R6E, Ferron Ss-abandoned, Dakota Grp-abandoned. Stone Cabin, Peters Point, Drunkards Wash, Grass Trail Creek, and Flat Canyon were producing in 1998.

| Field            | County           | Area             | Producing Formation | Cumulative Oil (bbl) | Production* Gas (bcf) |
|------------------|------------------|------------------|---------------------|----------------------|-----------------------|
| Stone Cabin      | Carbon, Duchesne | Uinta Basin      | Wasatch Fm          | 23                   | 0.72                  |
| Peters Point     | Carbon           | Uinta Basin      | Wasatch Fm          | 142,852              | 0.005                 |
| Farnham Dome.    | Carbon           | San Rafael Swell | Navajo Ss           | 0                    | 2.5                   |
| Gordon Creek     | Carbon           | Wasatch Plateau  | Permo-Triassic      | 0                    | 0                     |
| Drunkards Wash   | Carbon           | San Rafael Swell | Ferron coals        | -                    | 66                    |
| Grassy Trail Cr. | Carbon, Emery    | San Rafael Swell | Moenkopi Fm         | 540,000              | 0.145                 |
| Woodside Dome    | Emery            | San Rafael Swell | Permian Kaibab      | 0                    | 0                     |
| Last Chance, So. | Emery            | Wasatch Plateau  | Permo-Triassic      | 0                    | 0                     |
| Flat Canyon      | Emery            | Wasatch Plateau  | Dakota Ss           | 317                  | 1.44                  |
| Joe's Valley     | Sanpete          | Wasatch Plateau  | Ferron Ss           | 0                    | 2.63                  |
| "                | "                | "                | Dakota Grp          | 0                    | 2.65                  |

\* Production to 1993 ([Chidsey, 1991](#); [Hill and Bereskin, 1993](#)).

**Economic  
Characteristics:**

- a. Inert gas content**
- b. Recovery**
- c. Pipeline infrastructure**
- d. Exploration maturity  
relative to other basins**
- e. Sediment consolidation**
- f. Porosity/completion  
problems**
- g. Permeability**
- h. Porosity**

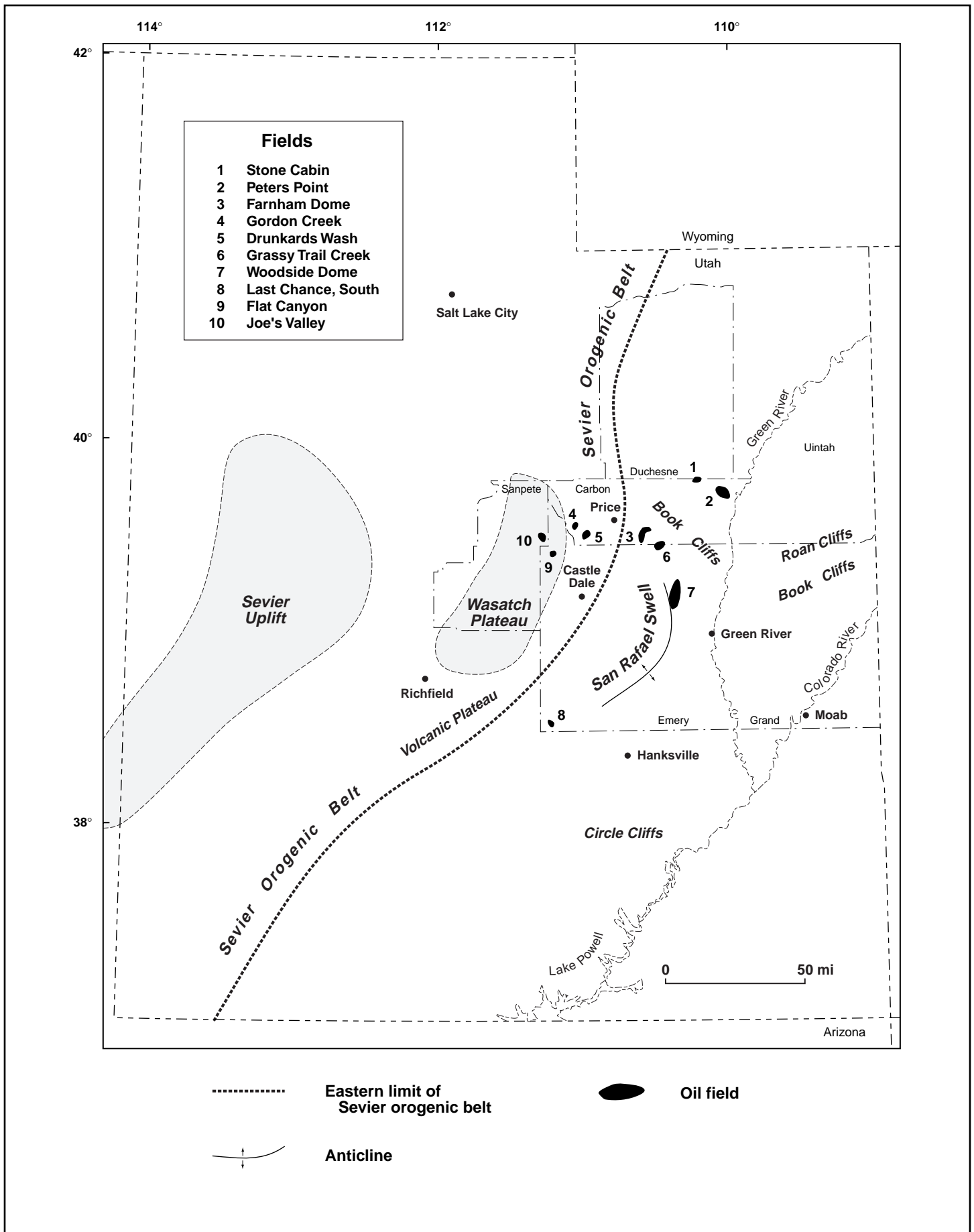


Figure 105. Location of the San Rafael Swell, Utah, showing approximate limits of Sevier orogenic belt and Wasatch Plateau. After [Peterson \(1994b\)](#), [Sprinkel \(1994\)](#), and [Willis \(1999\)](#).

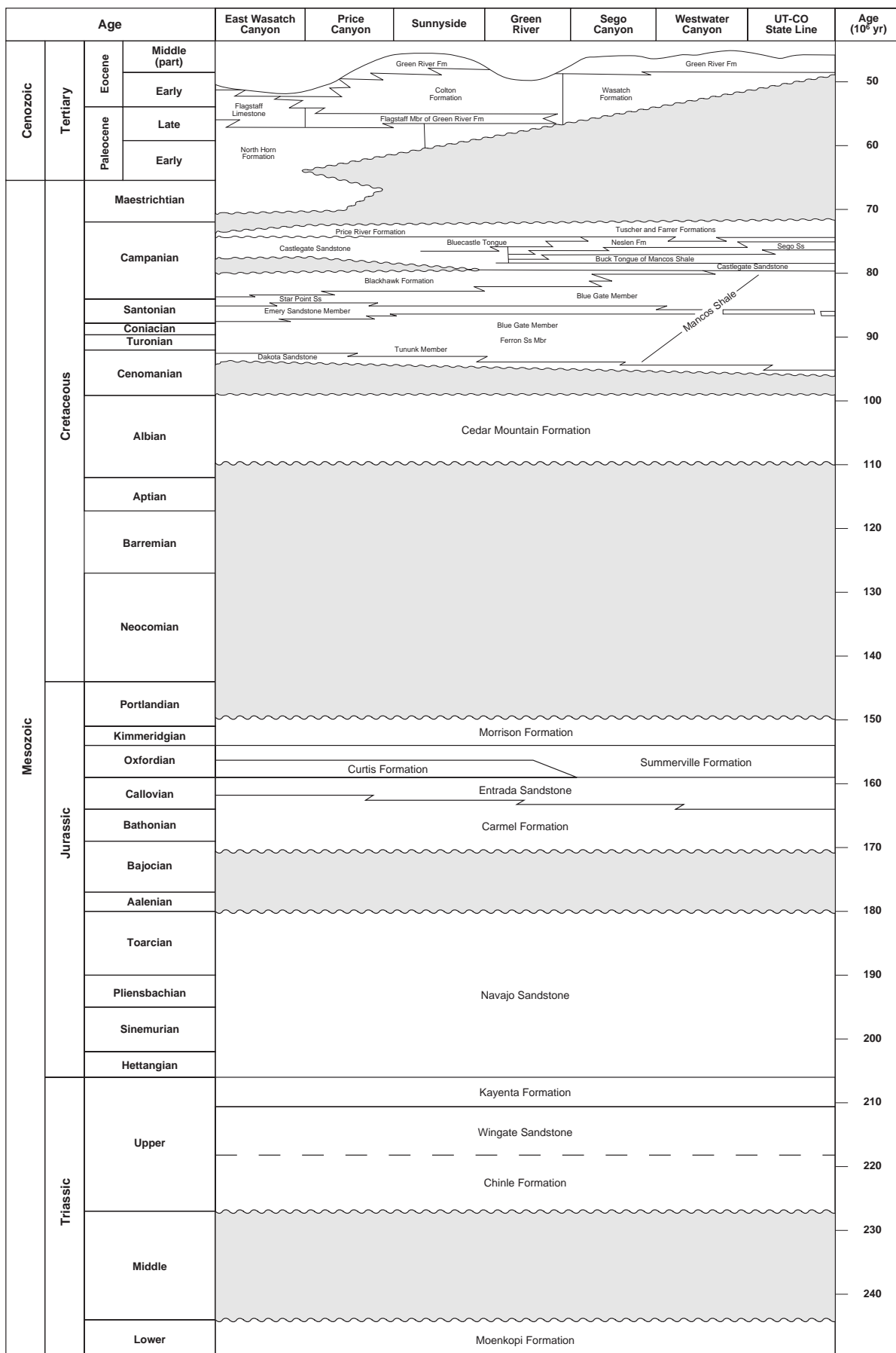


Figure 106. Generalized stratigraphic column for the Mesozoic and Cenozoic eras on the north end of the San Rafael Swell, Utah. After [McGookey et al. \(1972\)](#), [Hintze \(1988\)](#), [Eaton et al. \(1990\)](#), and [Fouch et al. \(1992\)](#).

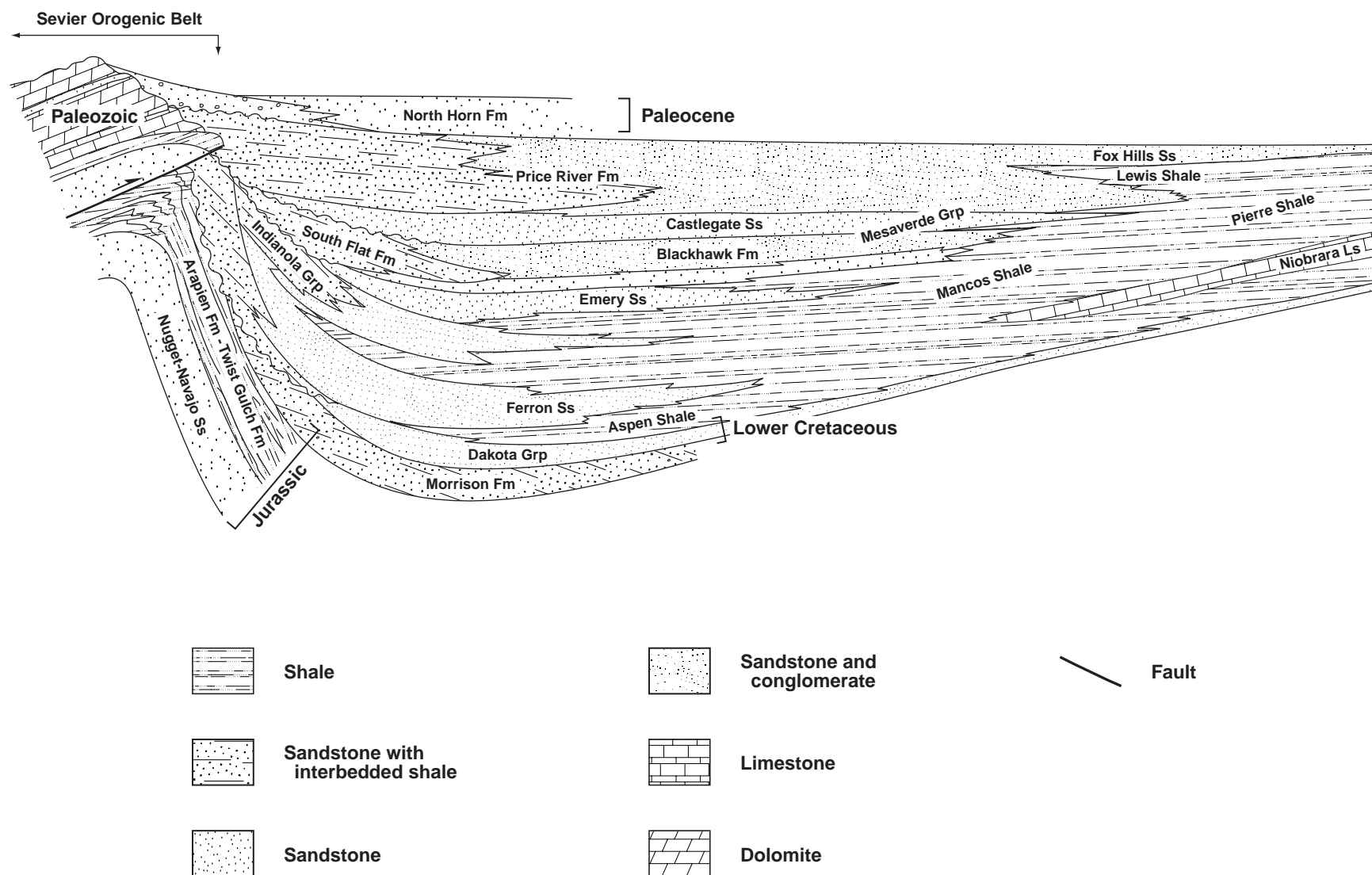


Figure 107. Diagrammatic cross section across the Rocky Mountain Geosyncline in central Utah. After [Armstrong \(1968\)](#).

## SANTA MARIA BASIN (MONTEREY FORMATION)

### GEOLOGIC SETTING

The Santa Maria basin is a triangular depression in the California coastal belt northwest of Los Angeles (Figure 108). The basin is 150 miles long and 10-50 miles wide and covers an area of 3000 square miles. The basin boundaries include the Santa Lucia and San Rafael Mountains on the north and northeast, respectively, the Santa Ynez Mountains on the south, and the Pacific Ocean on the west (Crawford, 1970; Dunham et al., 1991).

The basin originated with Andean-type subduction of North America's western margin during the late Mesozoic and middle Tertiary. Subduction progressed until the margin reached the East Pacific Rise at 30 Ma, after which the relative motion changed to right-slip displacement. The Neogene basins of western California developed in response to right-lateral shearing of the continental margin (Dunham et al., 1991).

The geotectonic history of the Santa Maria basin includes the following stages:

- 1) Late Cretaceous to early Miocene: right-slip movement along the Santa Maria River fault system and the Santa Ynez River fault to the south triggered initial subsidence and rifting of the basin (Dunham et al., 1991). Tectonic spreading may have formed pull-apart structures about 20-28 Ma (Hall, 1981). The initial rifting and basin subsidence deposited the coarse alluvial conglomerates of the Late Oligocene-Early Miocene Lospe Formation.
- 2) Miocene to Pliocene: continued wrench faulting resulted in rapid subsidence and development of a deep marine basin. Climatic and oceanographic changes produced favorable conditions for high plankton productivity in surface waters above the deep basin. The basin filled with organic-rich pelagic and hemipelagic sediments of the Monterey and Sisquoc Formations (Figure 109). Uplift of the Santa Ynez and San Rafael Mountains began during late Pliocene and contributed non-marine sediments.
- 3) Post-Miocene: tectonic style changed from right-slip motion to northeast-southwest-directed compression and resulted in thrust faulting. Reverse faults border or cut nearly every field in the Santa Maria Basin (Figure 110). These compressional structures formed some of the major oil-producing anticlines in the region (Dunham et al., 1991). The thickness of the deformed basin fill probably approaches 15,000 ft in the footwalls of reverse fault systems (Figure 110).

### HYDROCARBON PRODUCTION

The Santa Maria basin is one of the oldest oil-producing regions in California. Exploratory drilling began in the late 1890s near several oil seeps in the area. By 1908, major oil discoveries included the Orcutt, Lompoc, and Cat Canyon fields (Figure 108). The offshore Santa Maria basin has seen exploration since the 1950s; major offshore discoveries occurred in the 1980s and include the Point Pedernales, San Miguel, Bonito, and Sword fields. In 1981 Chevron discovered the Point Arguello field, the largest U.S. oil find since Alaska's Prudhoe Bay; Point Arguello estimated ultimate recovery (EUR) has exceeded 300 MMBO.

Offshore fields produce heavy oil, with gravities ranging from less than 5 to as light as 40° API (Dunham et al., 1991). Onshore basin oils have low gravities ranging from 16 to 27° API, and high sulfur and nitrogen content. Natural gas comprises only a small portion of the hydrocarbons. The gas occurs as solution gas or, rarely, as gas caps (Dryden et al., 1965; Dunham et al., 1991).

Net reservoir thickness averages 1000 ft and ranges from 50 to 3,000 ft. Porosities range from 15 to 20%, and permeabilities reach 1 darcy (Milton et al., 1996). Anticlines that formed above major reverse faults have trapped most oil and gas accumulation within the basin. To date, only one significant nonstructural field has a trap formed by a stratigraphic pinchout.

Several formations within the basin have yielded oil, but the naturally fractured siliceous shales and cherts of the Monterey Formation (Figure 109) have accounted for the greatest production. The Monterey ranges from 0 to 3000 ft thick and averages 1,000 ft (Figure 110) (Milton et al., 1996). The formation constitutes both a source rock and a reservoir. Organic-rich zones occur as 1.5 to 6.5 ft thick shale layers, interbedded with thin dolomite beds in the lower and middle members of the formation. Kerogen content commonly exceeds 5% and locally exceeds 18% within some shale beds. However, though interbedded with fractured reservoir rocks, those same shales may not have generated the oil. Instead, oil may have migrated a considerable distance up dip along fractures before becoming structurally trapped.

Monterey organic matter is mostly amorphous algal material which matures at a significantly faster rate than structured organic debris such as vitrinite. Thus, vitrinite reflectance has proven unreliable as a maturity indicator. Monterey oils may have originated at unusually low temperatures because of the unusual formation chemistry. Rapid basin subsidence may have accelerated the entry of Monterey source rocks into the oil generation zone. In many areas of the basin, the Monterey Formation lies at depths where temperatures exceed 120 °C which is within the classic oil window (Dunham et al., 1991).

## **EVIDENCE FOR BASIN-CENTERED GAS**

Santa Maria basin source rocks contain mostly Type II oil-prone organic matter. To generate significant gas from Type II kerogens, the oil requires thermal cracking through deep burial. The window for oil-to-gas conversion occurs at a Tmax of 460 °F, and vitrinite reflectance (Ro) must exceed 1.2%. Unfortunately, vitrinite reflectance is not a reliable indicator for the Monterey Formation.

Extrapolation of French's geothermal gradient for three fields in the Santa Maria basin indicates the deepest part of the basin (12,000-15,000 ft) has sufficient temperature and burial depth for gas generation and/or conversion from Type II kerogen (Magoon and Isaacs, 1983). This analysis assumes removal of 3000 ft of overburden. As the thickness of fill approaches 15,000 ft (Magoon and Isaacs, 1983; Tennyson, 1996), only the deepest part of the basin may be mature enough for basin-centered gas accumulation.

## KEY ACCUMULATION PARAMETERS

### Identification

Pacific Coast- Santa Maria basin, southern California. fractured chert and dolomite and cherty shale of middle to late Miocene Monterey formation

### Geologic Characterization of Accumulation:

- |                                                 |                                                                                                                                                                                                       |
|-------------------------------------------------|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <b>a. Source/reservoir</b>                      | Monterey formation; source-organic rich shales; reservoir-fractured brittle rocks (chert and carbonate).                                                                                              |
| <b>b. Total Organic Carbons (TOCs)</b>          | 17% (average 5%)                                                                                                                                                                                      |
| <b>c. Thermal maturity</b>                      | Type II Kerogen; $R_o$ is an unreliable indicator here; maturity established by depth of burial plots.                                                                                                |
| <b>d. Oil or gas prone</b>                      | Both heavy oil (12 to 35 degrees API) and gas prone (associated gas only).                                                                                                                            |
| <b>e. Overall basin maturity</b>                | Considered marginally mature to mature; immature in some places.                                                                                                                                      |
| <b>f. Age and lithologies</b>                   | Fractured chert and cherty shale of middle to late Miocene Monterey Formation.                                                                                                                        |
| <b>g. Rock extent/quality</b>                   | Basin-wide source and reservoir-rock distribution.                                                                                                                                                    |
| <b>h. Potential reservoirs</b>                  | Fractured Monterey Formation.                                                                                                                                                                         |
| <b>i. Major traps/seals</b>                     | Producing fields-structural (nearly every field in the basin is bounded or cut by reverse faults); stratigraphic pinchouts.                                                                           |
| <b>j. Petroleum generation/migration models</b> | Migration began in the late Miocene and likely continues to the present in tectonically subsiding regions of the basin where immature Monterey shales are only now being carried into the oil window. |
| <b>k. Depth ranges</b>                          | 1,300 to 10,000 ft (producing fields); 12,000-15,000 ft in the basin center.                                                                                                                          |
| <b>l. Pressure gradients</b>                    |                                                                                                                                                                                                       |

**Production and Drilling  
Characteristics:**

- |                                       |                                                                                                                                                                                                                                                                         |
|---------------------------------------|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <b>a. Important fields/reservoirs</b> | Orcutt, Lompoc, Casmalia, Cat Canyon, Santa Maria Valley Field, Point Arguello, Point Pedernales, and San Miguel                                                                                                                                                        |
| <b>b. Cumulative production</b>       | Orcutt (disc. 1901, >180 MMBO); Lompoc (>47 MMBO); Casmalia (50 MMBO); Cat Canyon (298 MMBO, 178 BCFG); Santa Maria Valley Field (184 MMBO); Point Arguello (disc 1981, 123 MMBO); Point Pedernales (disc. 1983, 20,000 BBO/day); San Miguel (disc. 1983, 3780 BBO/day) |

**Economic  
Characteristics:**

- |                                                         |                                                                                                                                                                                                               |
|---------------------------------------------------------|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <b>a. Inert gas content</b>                             | CO <sub>2</sub> : 20%-25% ( <a href="#">Dryden et al., 1965</a> ); sulfur; nitrogen                                                                                                                           |
| <b>b. Recovery</b>                                      | Low. Continuous-type accumulations are characterized by low individual well-production rates and small well-drainage area. Directional/horizontal wells are being drilled to reduce the number of well sites. |
| <b>c. Pipeline infrastructure</b>                       | Very good. There are numerous gas lines in the basin.                                                                                                                                                         |
| <b>d. Exploration maturity relative to other basins</b> |                                                                                                                                                                                                               |
| <b>e. Sediment consolidation</b>                        | Consolidation/porosity reduction occurs with depth of burial .                                                                                                                                                |
| <b>f. Porosity/completion problems</b>                  | No problems; fractured reservoirs; porosity = 15-20%.                                                                                                                                                         |
| <b>g. Permeability</b>                                  |                                                                                                                                                                                                               |
| <b>h. Porosity</b>                                      |                                                                                                                                                                                                               |

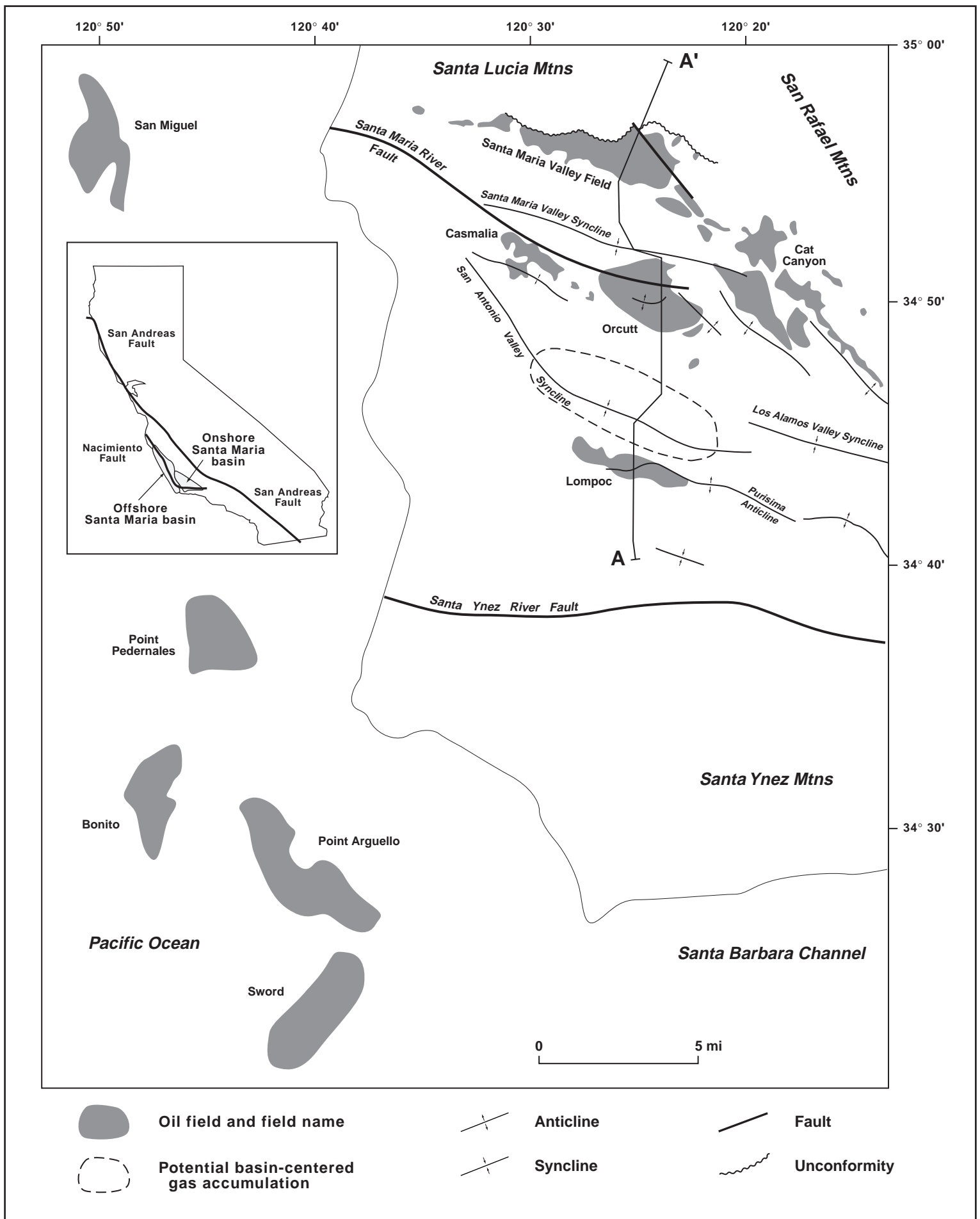


Figure 108. Index map of the Santa Maria Basin, California, showing locations of major structural features, onshore and offshore oil fields, potential basin-centered gas accumulation, and cross section A-A' (see Figure 110). After Magoon and Isaacs (1983), Sorensen et al. (1995), and Honjas et al. (1999, in preparation).

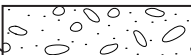
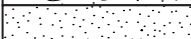
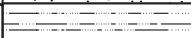

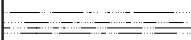



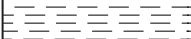
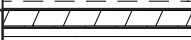

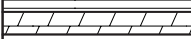


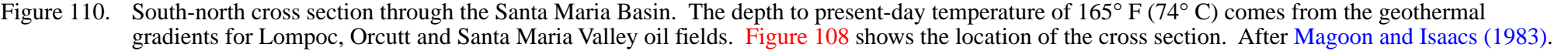
| System     | Series        | Unit                          | Lithology                                                                           | Description                                                                        |                                             |
|------------|---------------|-------------------------------|-------------------------------------------------------------------------------------|------------------------------------------------------------------------------------|---------------------------------------------|
| Quaternary | Pleistocene   | Paso Robles Formation         |   | Conglomerate                                                                       |                                             |
| Tertiary   | Pliocene      | Careaga Sandstone             |   | Sandstone                                                                          |                                             |
|            |               | Foxen Mudstone                |   | Shale and siltstone                                                                |                                             |
|            |               | Repettian equivalent Mudstone |   |                                                                                    |                                             |
|            |               | Sisquoc Formation             |   | Diatomaceous mudstone<br>Siliceous mudstone                                        |                                             |
|            | Upper Miocene | Upper Monterey Formation      |   | Interbedded siliceous<br>shale and dolomite                                        |                                             |
|            |               | Middle Monterey Formation     |   |                                                                                    |                                             |
|            |               | Middle Miocene                | Lower Monterey Formation                                                            |  | Phosphatic shale                            |
|            | Lower Miocene |                               | Point Sal Formation                                                                 |  | Interbedded siliceous<br>shale and dolomite |
|            |               |                               | Tranquillon Volcanics<br>Lospe Conglomerate                                         |  |                                             |
|            | Cretaceous    |                               | Espada (?) Formation                                                                |  | Shale and sandstone                         |
| Cretaceous |               | Espada (?) Formation          |   | Sheared and compacted<br>shale and siltstone                                       |                                             |
| Jurassic   |               | Point Sal Ophiolite           |   | Chert-basalt-gabbro<br>and/or melange                                              |                                             |
|            |               | Franciscan Complex            |  |                                                                                    |                                             |

Figure 109. Stratigraphic column of the onshore Santa Maria Basin, California. After [Dunham et al \(1986\)](#).



## **SNAKE RIVER DOWNWARP, IDAHO**

### **GEOLOGIC SETTING**

The Snake River Downwarp is a generally east- to west-trending arcuate depression in southern Idaho and east-central Oregon (Figure 111). The Snake River (Figure 112) traverses the entire length of the province. The area's boundaries include the Columbia Plateau to the northwest, the Idaho Batholith to the north, the Montana thrust belt to the northeast, and the Yellowstone Plateau to the east. The Wyoming Overthrust Belt forms the southeastern border, while the Basin and Range province marks the southern to western limits.

Until the Miocene, the downwarp existed as a relatively stable part of the Cordilleran miogeoclinal continental shelf. Onset of rifting during the Miocene created the present interior rift basin (Warner, 1977), and included normal block-faulting and left-lateral strike-slip faulting. At this time ancient Lake Bruneau formed and covered much of southern Idaho and adjacent parts of Oregon and Washington. Lake Bruneau shrank in size as rifting progressed, and by Pliocene time, a smaller remnant—Lake Idaho—occupied only the down-dropped central rift graben (Warner, 1977; 1980). The deepest part of Lake Bruneau was in the southwest part of the present basin, immediately north of the Owyhee Mountains (Figure 112). During the Pliocene, rifting shifted the axis of Lake Bruneau's structural basin 12 miles northward, and lowered the basin's northern flank relative to the southern. This became the primary depositional axis for Pliocene Lake Idaho, which expanded eastward almost to Wyoming (Figure 113).

Paleozoic rocks vary from 0 to 45,000 ft thick in the downwarp, and thicken to over 15,000 ft in the surrounding area. Mesozoic strata thickness may reach 50,000 ft, but generally ranges from 15,000 to 30,000 ft in the downwarp area (Warner, 1980). The Miocene Sucker Creek Formation includes up to 3,500 ft of Lake Bruneau sediments (Figure 114). Lake Idaho deposits range to 9,000 ft in thickness and comprise the Poison Creek, Chalk Hills and Glens Ferry Formations of the Idaho Group (Peterson, 1996). The thickest strata for both lakes occur in the western parts of their depositional basins (Figure 115).

The downwarp area shows a high present-day geothermal gradient, probably resulting from emplacement of the Cretaceous Idaho Batholith (Figure 115). Various events have subjected the area to high-heat flows: the Miocene rifting and related extrusion of the Columbia Plateau Basalt and Owyhee Volcanics; and Pliocene to Recent extrusion of the Snake River Basalt.

### **HYDROCARBON PRODUCTION**

There is no existing or historical production in the area. Potential reservoirs include interbedded sands in the Idaho Group and the Sucker Creek Formation. Fracture production is possible from nearly any rock type containing an overpressured basin-centered accumulation.

### **EVIDENCE FOR BASIN-CENTERED GAS**

Factors that may indicate a basin-centered gas accumulation include abundant gas shows, and some oil shows from both water wells and hydrocarbon exploration wells. Warner (1980) and Peterson (1996) speculate that the Cenozoic section in the Snake River Downwarp may total 30,000 ft thick. To date, some drilling has occurred in horizons above 5,000 ft depth, but very little in the strata between 5,000 and 14,000 ft depth (Figure 112). Sediments at all depths appear to contain some hydrocarbons, although Miocene to Pliocene lacustrine sediments are most favorable for basin-centered accumulations. Because of the probable great depth and high thermal gradient in the basin, the deeper areas will only generate gas and may actually be at the peak to past-peak generation stage, depending on depth and location.

## KEY ACCUMULATION PARAMETERS

### Identification

Rocky Mountain Province; Snake River Downwarp in Southern Idaho.  
Possible Cenozoic Basin Centered Gas.

### Geologic Characterization of Accumulation:

- a. Source/reservoir** Lacustrine rocks, shale and mudstone of the Tertiary Pliocene Idaho Group and the Miocene Sucker Creek Fm (Wood, 1994).
- b. Total Organic Carbons (TOCs)** In the Halbouty 1 J. N. James exploratory well (Figure 112), the 10 highest TOC samples ranged from 0.43 to 1.95% (Wood, 1994).
- c. Thermal maturity** Pliocene Idaho Group: immature for the depth range 1000 to 2100 ft; Ro ranges from 0.2 to 0.7 (estimated from reported vitrinite colors) (Senftle and Landis, 1991); Rocks of probable Miocene age, below the seismic "Miocene Volcanics acoustic basement," are mature and range from Ro 0.7 - 1.3 at 3840 ft to 2.0 at 8700 ft depth (estimated from an orange-brown to dark brown vitrinite color) (Senftle and Landis, 1991). This is in the wet gas to dry gas zone. Untested strata, between 2100 ft and 3840 ft, may be within the oil generating window (Wood, 1994). Kerogen is primarily woody, with secondary amounts of herbaceous spores, pollen and inertinite. This strata will be a good gas source and a poor oil source. Geothermal gradients in the Western Snake River Downwarp are high, ranging from 16.5 to 22° F per 1000 ft (30 - 40° C) (Wood, 1994, p. 109).
- d. Oil or gas prone** Probably gas prone with associated gas liquids. Gas from a depth of 1979 ft in Oroco-Simplot 1 Virgil Johnson (Figure 112) indicated 93% methane, 3% ethane, and 4 % unknown; Btu was 1102 per cu ft (IHS Eneery Group, 2000, PI/Dwights Plus™).
- e. Overall basin maturity** Probably mature; overmaturity may occur in Paleozoic strata at great depth. Mid-depth Mesozoic and early Cenozoic strata could possibly be overmature.
- f. Age and lithologies** Clastic and lacustrine strata of the Pliocene Idaho Group and Miocene Sucker Creek Formation.
- g. Rock extent/quality** Potentially large extent of possible interbedded lacustrine source and clastic reservoir strata.
- h. Potential reservoirs** Interbedded sands in the Idaho Group and Sucker Creek Formation
- i. Major traps/seals** Possibility of both structural and stratigraphic types
- j. Petroleum generation/migration models** Weimer's (1996) "Cooking Pot" model, where generated hydrocarbons are expelled into the surrounding reservoir rocks.
- k. Depth ranges** Biogenic gas to 5000 ft depth. Speculative basin-centered gas from 5000 to 25,000-plus ft (Warner, 1980)

|                              |                                                                                                        |
|------------------------------|--------------------------------------------------------------------------------------------------------|
| <b>l. Pressure gradients</b> | 0.45 psi/ft ( $\pm 0.06$ psi/ft) for shallow objectives. Deeper objectives are possibly overpressured. |
|------------------------------|--------------------------------------------------------------------------------------------------------|

**Production and Drilling  
Characteristics:**

|                                       |      |
|---------------------------------------|------|
| <b>a. Important fields/reservoirs</b> | none |
|---------------------------------------|------|

|                                 |      |
|---------------------------------|------|
| <b>b. Cumulative production</b> | none |
|---------------------------------|------|

**Economic  
Characteristics:**

|                             |               |
|-----------------------------|---------------|
| <b>a. Inert gas content</b> | Less than 5%. |
|-----------------------------|---------------|

|                    |  |
|--------------------|--|
| <b>b. Recovery</b> |  |
|--------------------|--|

|                                   |                                                                                                                                                                                                                                |
|-----------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <b>c. Pipeline infrastructure</b> | A single 24-inch pipeline passes through the area paralleling Interstate 84. Several small lateral lines serve the towns surrounding Boise, Idaho. A major trunk line runs from the southwest corner of Idaho to Reno, Nevada. |
|-----------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|

|                                                         |           |
|---------------------------------------------------------|-----------|
| <b>d. Exploration maturity relative to other basins</b> | Immature. |
|---------------------------------------------------------|-----------|

|                                  |                                                                          |
|----------------------------------|--------------------------------------------------------------------------|
| <b>e. Sediment consolidation</b> | Poorly consolidated rocks may exist in the shallower parts of the basin. |
|----------------------------------|--------------------------------------------------------------------------|

|                                        |                                                                                                         |
|----------------------------------------|---------------------------------------------------------------------------------------------------------|
| <b>f. Porosity/completion problems</b> | Low porosity and permeability may be a problem, at least in underpressured or normally pressured areas. |
|----------------------------------------|---------------------------------------------------------------------------------------------------------|

|                        |  |
|------------------------|--|
| <b>g. Permeability</b> |  |
|------------------------|--|

|                    |  |
|--------------------|--|
| <b>h. Porosity</b> |  |
|--------------------|--|

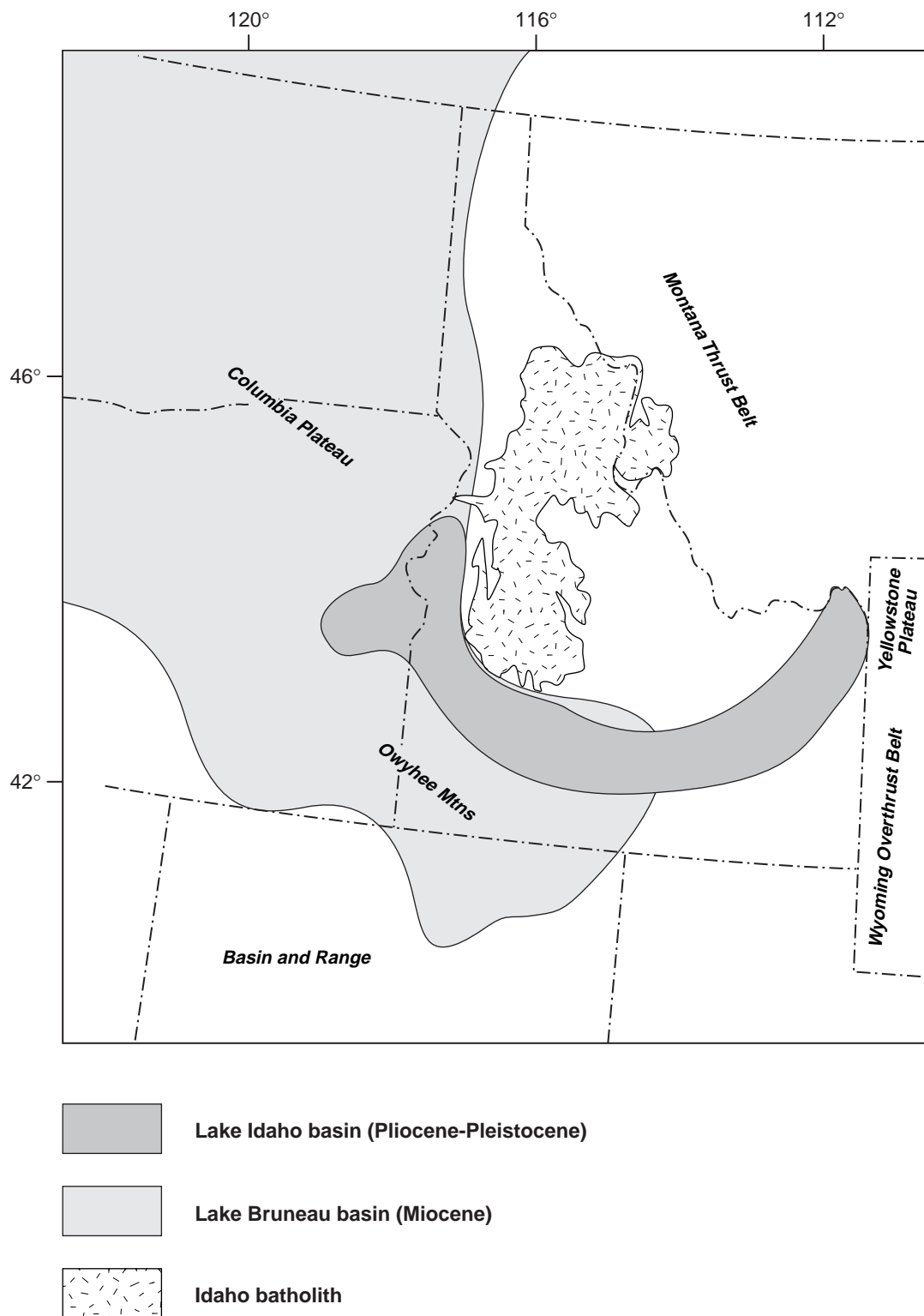
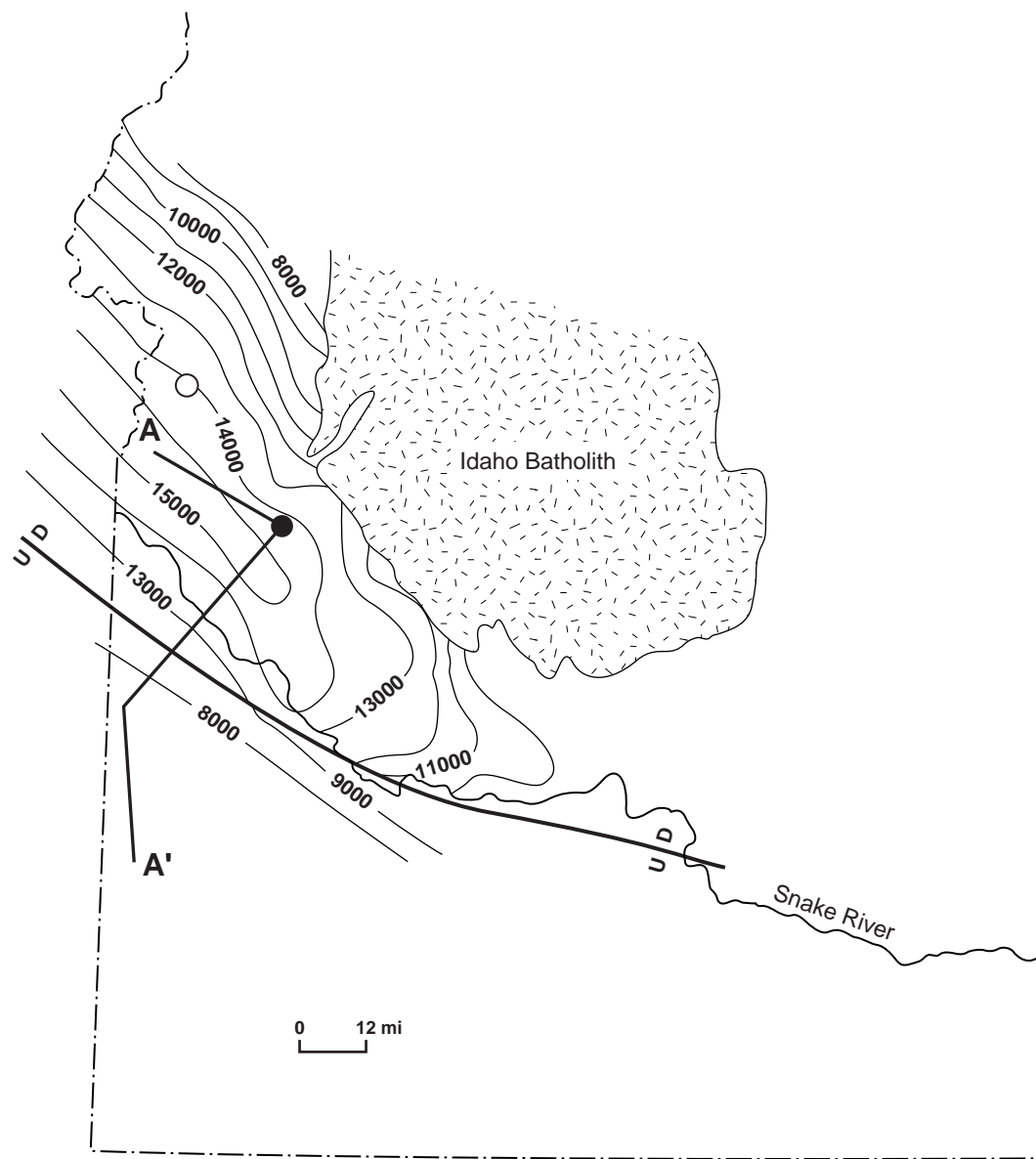


Figure 111. Map of Snake River downwarp area in southwest Idaho, showing Cenozoic lake basins and Idaho batholith. The Snake River downwarp corresponds roughly to the area shown as Lake Idaho basin, the down-dropped central rift graben representing the final remnant of Lake Bruneau. After [Warner \(1981\)](#).



Igneous rock



Fault; U is upthrown side, D is downthrown side



Halbouty-Chevron 1 J. N. James

Hydrocarbon exploration well; drilled in 1976. SE 27, T4N R1W. Total depth = 14,000 ft.  
Total Organic Carbon range 0.43 to 1.95%.



Oroco-Simplot 1 Virgil Johnson

Hydrocarbon exploration well; drilled in 1955. SE 27, T8N R4W. Total depth = 4,040 ft.  
Well suffered gas blowout at 1,979 ft depth.  
Gas analysis: 1102 Btu/ft<sup>3</sup>, 93% methane, 3% ethane, 4% unknown.

Figure 112. Isopachs showing total thickness of Pliocene and Sucker Creek strata, Snake River downwarp, Southwest Idaho. Contour interval is 1000 ft. Possible basin-centered gas at 200° F. The peak hydrocarbon generation isotherm occurs at approximately 9,400 ft and greater depth. The map shows the location of cross-section A-A' (Figure 115). After Warner (1977).

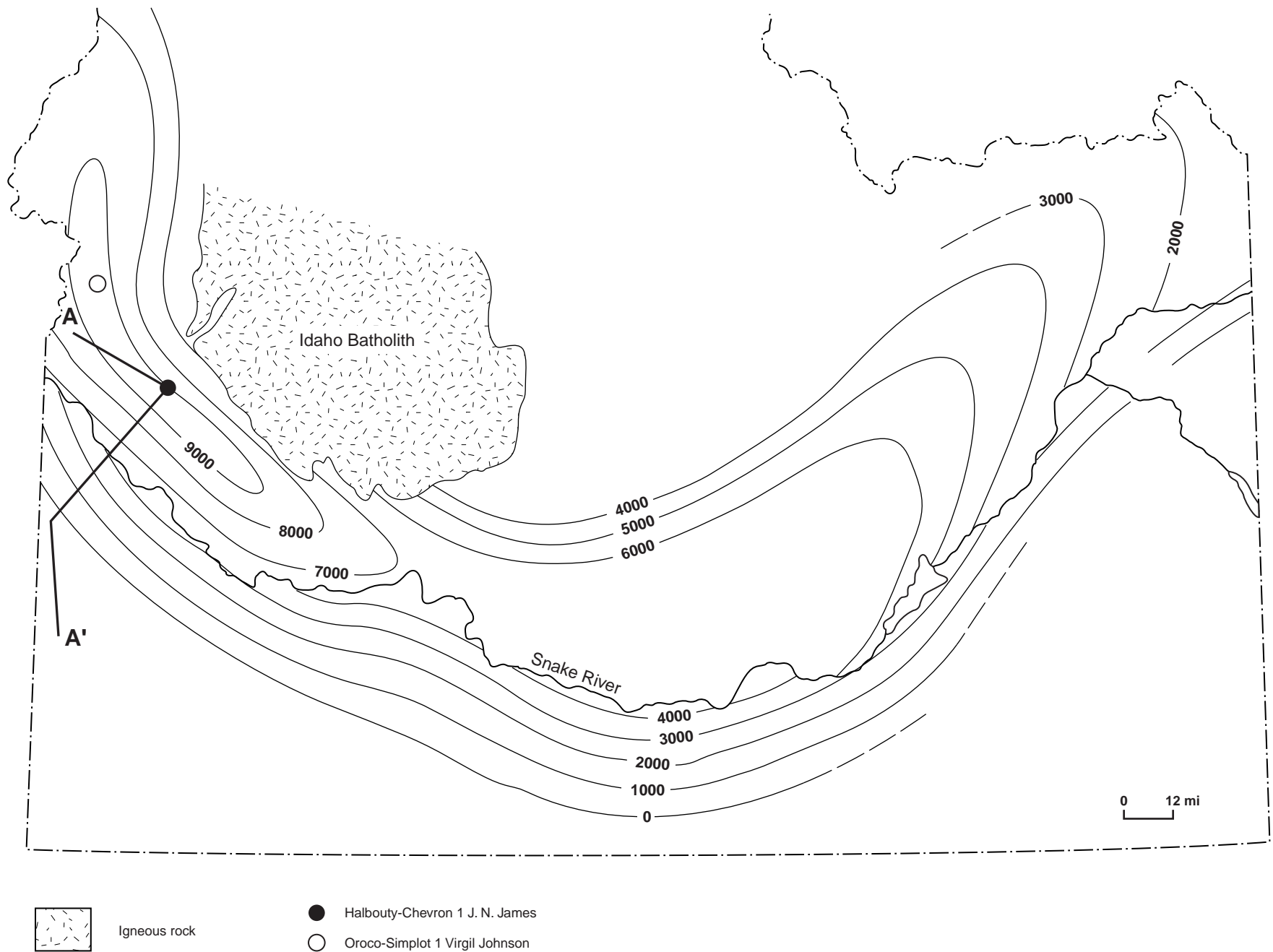


Figure 113. Isopach of post-Sucker Creek Cenozoic strata, Snake River downwarp, southwest Idaho. Contour interval is 1000 ft. After [Warner \(1977\)](#).

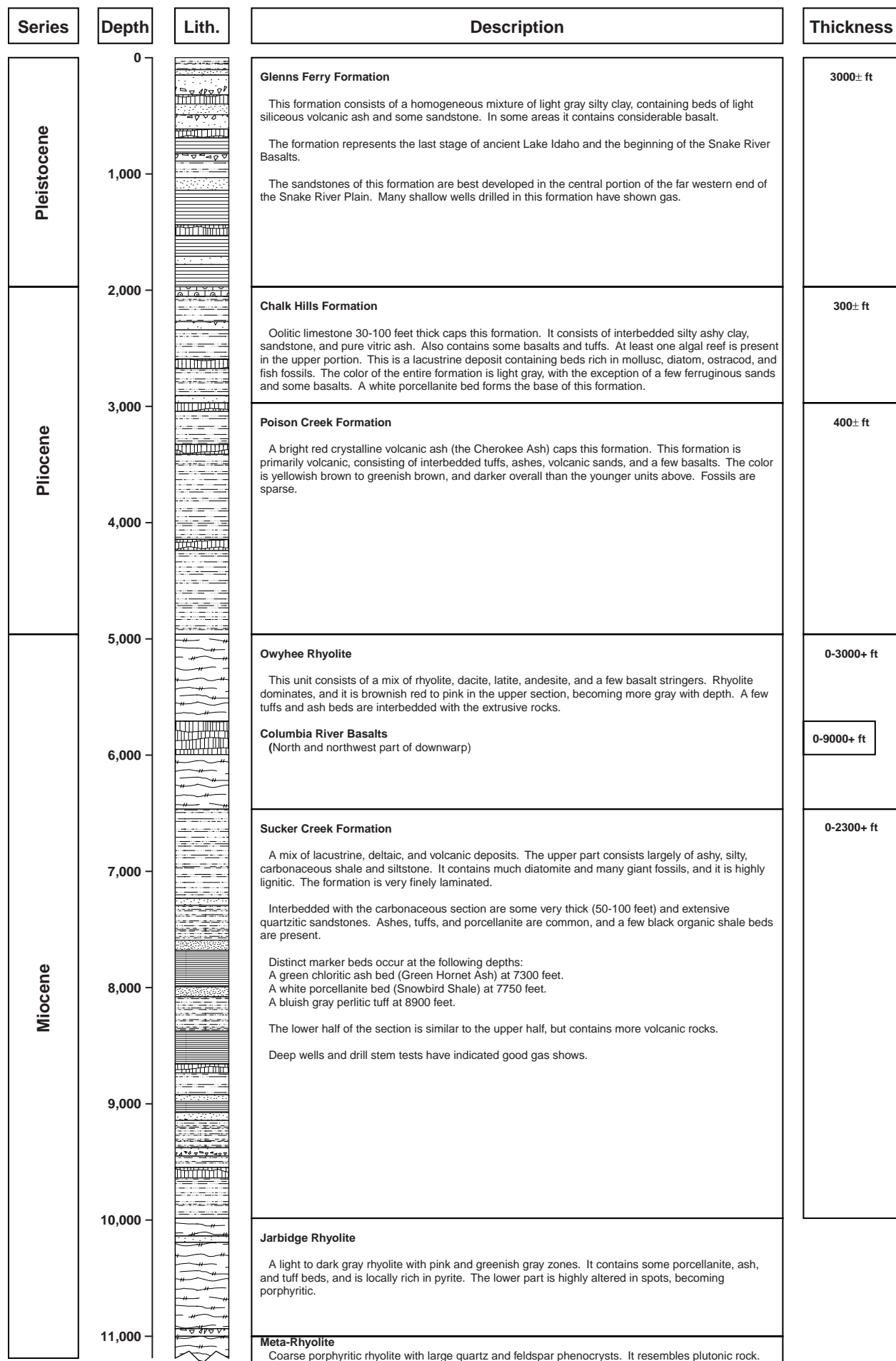


Figure 114. Cenozoic stratigraphic column of the western Snake River Downwarp, Idaho. After Warner (1981) and Wood (1994).

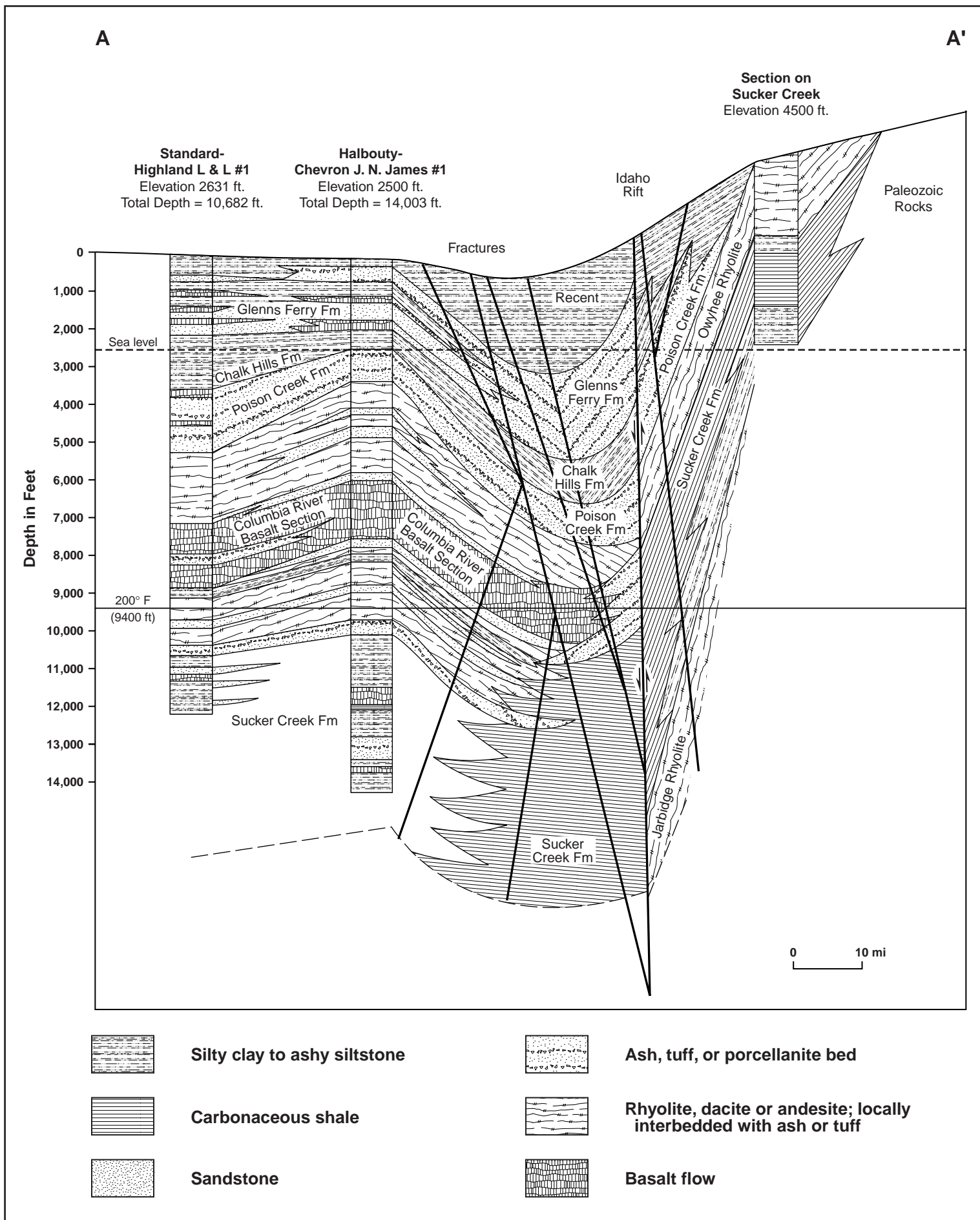


Figure 115. North-south cross section A-A', western Snake River Downwarp (Figure 112 shows the section location). Section shows the relationship between the stratigraphy and the estimated 200° F isotherm (derived by assuming an average annual surface temperature of 50° F). The 200° isotherm represents a possible present-day top-of-the-peak hydrocarbon generation window. After Warner (1977).

## SWEETGRASS ARCH (CENTRAL MONTANA)

### GEOLOGIC SETTING

The Sweetgrass Arch is a gentle fold extending from northcentral Montana into southern Alberta, Canada ([Figure 116](#)). The Montana Disturbed Belt forms the western border, the Bearpaw Mountains bound the arch on the east, and the Little Belt Mountains closes off the arch to the south.

The Basin contains Paleozoic and Mesozoic sediments; but Ordovician, Silurian, Pennsylvanian and Permian strata are absent because of erosion or non-deposition ([Figures 117 and 118](#)). An unconformity separates Mississippian from Jurassic rocks in the area ([Figure 117](#)). Cretaceous rocks dominate the remaining sedimentary section ([Figure 118](#)) ([Peterson, 1966](#)).

The late Cretaceous to early Tertiary Laramide orogeny gave the basin its present configuration.

### HYDROCARBON PRODUCTION

[Figure 116](#) shows a map of oil and gas fields in the Sweetgrass Arch area. The Cut Bank field is the largest and represents a stratigraphic trap in the Cretaceous Cutbank Sandstone. Cumulative production to date exceeded 168 MBO and 322 BCFG. Blackleaf Canyon field produces from the Mississippian Sun River Dolomite within a Disturbed Belt thrust sheet; to date the field has produced over 33,000 BO and more than 7 BCFG. The Two Medicine Field has produced more than 25,000 BO from the Cone Member fractured shales in the Upper Cretaceous Marias River Formation, and more than 11,000 BO and 274 BCFG from the Sun River Dolomite.

The source rock for most fields in the area is the Devonian-Mississippian Bakken Shale. Although Bakken oil and gas generation occurred at great depth in the Alberta Basin (north of the Sweetgrass Arch), fracturing in the Sun River Dolomite and across the Mississippian-Jurassic unconformity allowed extensive gas migration updip and southward into the Cutbank Sandstone ([Dolson et al., 1993](#)).

### EVIDENCE FOR BASIN-CENTERED GAS

Studies of potential source rocks in the Disturbed Belt indicate the Cone Member of the Marias River Formation, and the Bakken Shale show the greatest potential for hydrocarbon generation ([Clayton et al., 1982](#)). These rocks are generally immature east of the Disturbed Belt ([Figure 119](#)), although the Bakken may be mature to post-mature where buried by thrust sheets ([Clayton et al., 1982](#); [Dolson et al., 1993](#)). Vitrinite reflectance (Ro) for the Bakken ranges from less than 0.5 to 1.5% ([Dolson et al., 1993](#)) ([Figure 119](#)). Potential reservoirs include Devonian Nisku and Three Forks Formations, Jurassic Swift and Sawtooth Formations, and sandstones in the Cretaceous Blackleaf and Kootenai Formations.

The Sweetgrass Arch has little apparent potential for continuous basin-centered gas accumulations. Conventional accumulations in the area have produced large volumes of oil and gas, but the gas migrated from deeper zones along the Disturbed Belt.

## KEY ACCUMULATION PARAMETERS

### Identification

Rocky Mountain, Central Montana

### Geologic Characterization of Accumulation:

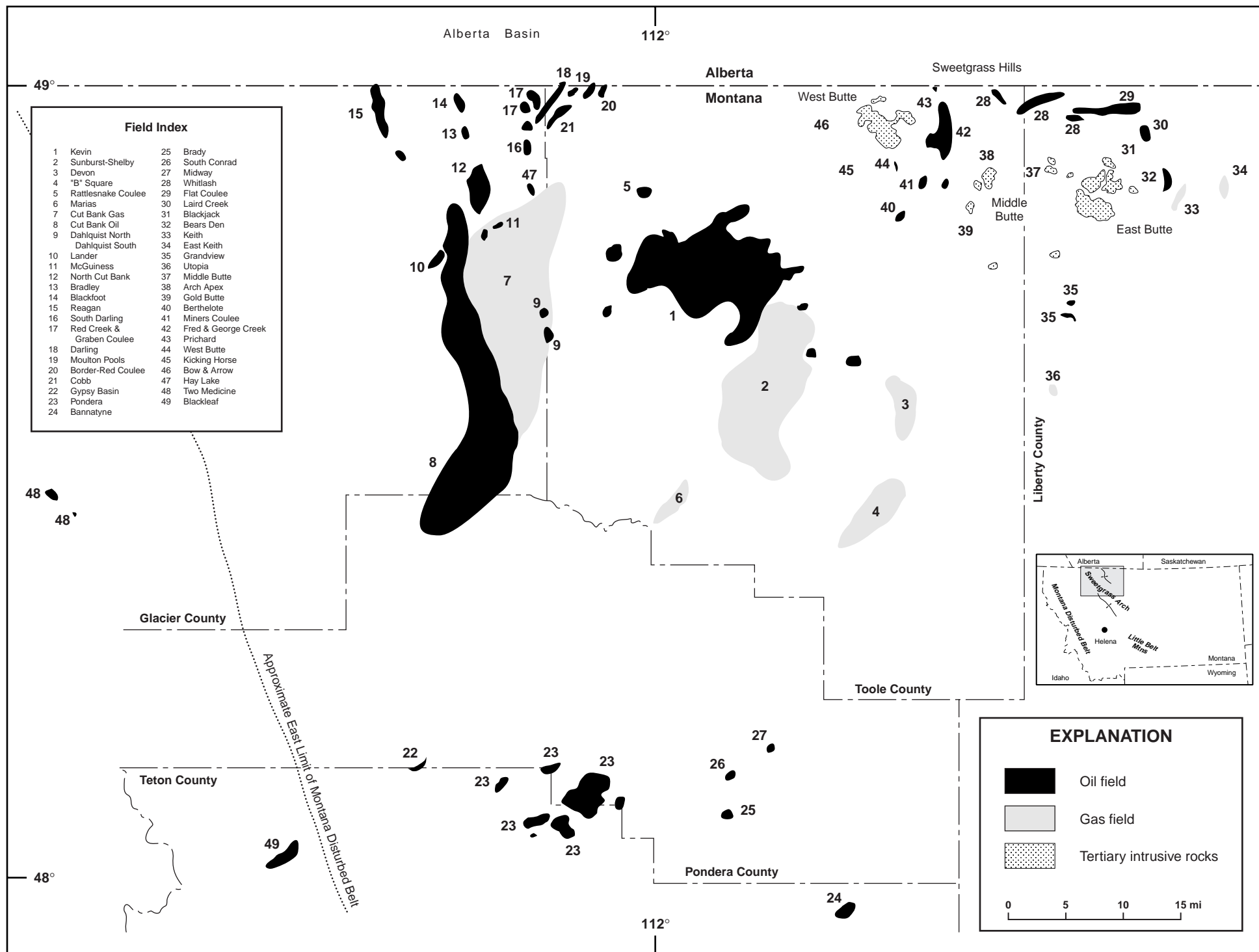
- a. Source/reservoir** Potential sources: Bakken Shale and Cone Member, Marias River formation; potential reservoirs: Devonian Nisku and Three Forks formations, Jurassic Swift and Sawtooth Formations, and sandstones in the Cretaceous Blackleaf and Kootenai Formations.
- b. Total Organic Carbons (TOCs)** Devonian Three Forks/Bakken avg = 0.975% ([Dolson et al, 1993](#)); Cretaceous Cone Member, Marias River Formation avg = 2.40% ([Clayton et al., 1982](#)).
- c. Thermal maturity** Bakken Shale  $R_o$  = <5% to 1.5% beneath thrusts of Montana Disturbed Belt. Cretaceous shales of Sweetgrass Arch to east edge of Disturbed Belt,  $R_o$  0.6% threshold (so Cretaceous Cone Shale is immature along the Sweetgrass Arch) ([Figure 119](#)) ([Dolson et al, 1993](#)).
- d. Oil or gas prone** Bakken Fm source rocks are thermally immature throughout the productive portion of the Sweetgrass Arch ([Dolson et al., 1993](#)).
- e. Overall basin maturity** Mature only in deeper portion to north in Canada and beneath thrust plates of the Disturbed Belt along the western margin.
- f. Age and lithologies**
- g. Rock extent/quality**
- h. Potential reservoirs**
- i. Major traps/seals**
- j. Petroleum generation/migration models**
- k. Depth ranges**
- l. Pressure gradients**

**Production and Drilling  
Characteristics:**

- a. Important  
fields/reservoirs**
- b. Cumulative production**

**Economic  
Characteristics:**

- a. Inert gas content**
- b. Recovery**
- c. Pipeline infrastructure**    Good near conventional fields.
- d. Exploration maturity  
relative to other basins**
- e. Sediment consolidation**
- f. Porosity/completion  
problems**
- g. Permeability**
- h. Porosity**



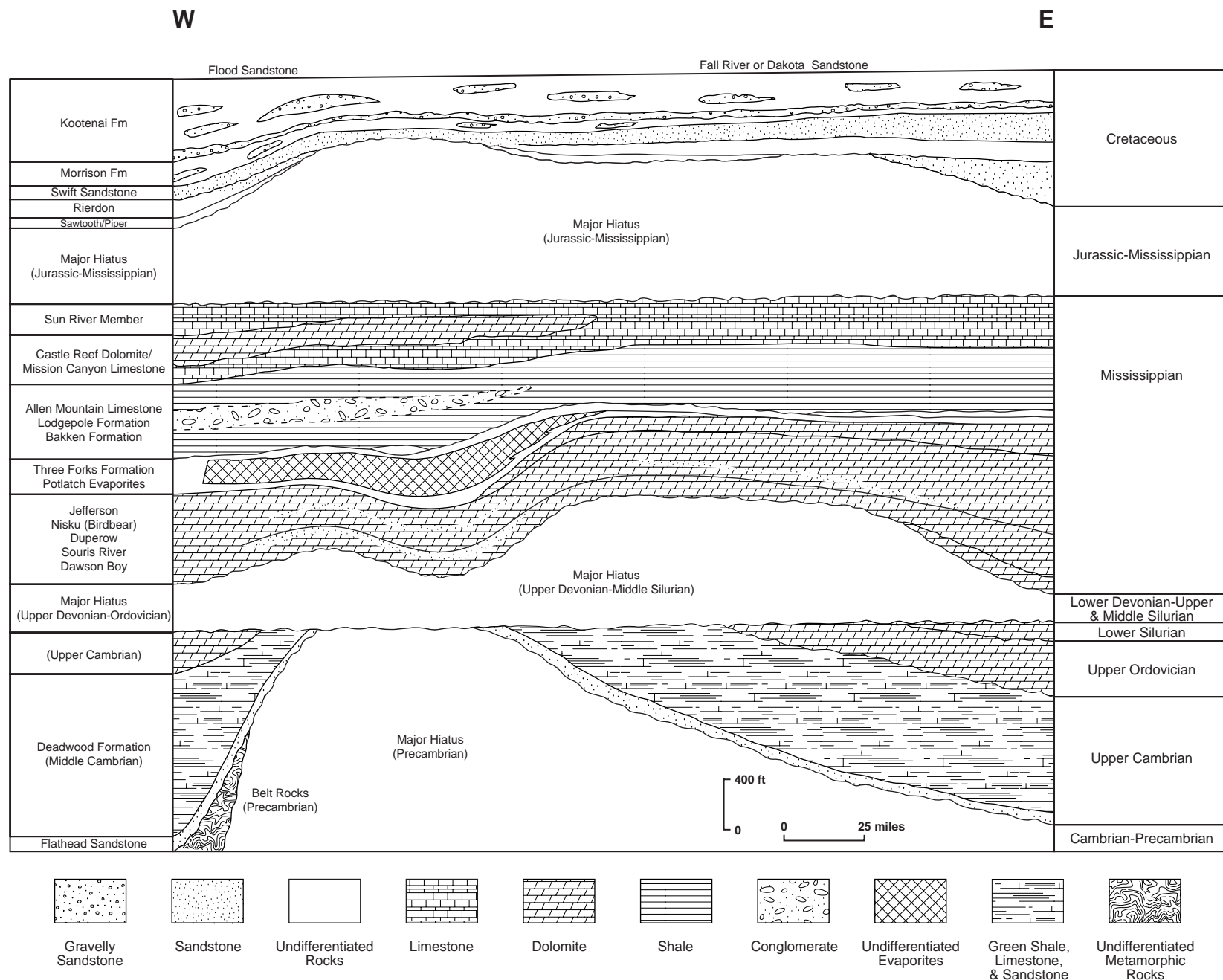


Figure 117. West-to-east cross section across Sweetgrass Arch in central Montana, showing major depositional units and intervening major depositional interruptions. Modified from [Peterson \(1966\)](#).

| System              |             | Sweetgrass Area<br>Northwest Montana             |                              |                                   | Southern Plains<br>Alberta |                                              |                   | Southwest<br>Saskatchewan                    |           |       |  |
|---------------------|-------------|--------------------------------------------------|------------------------------|-----------------------------------|----------------------------|----------------------------------------------|-------------------|----------------------------------------------|-----------|-------|--|
| Cretaceous          | Upper       | Bear Paw<br>Judith River<br>Claggett<br>Eagle    |                              |                                   |                            |                                              |                   |                                              |           |       |  |
|                     |             | Colorado                                         | Marias<br>River Shale        | Niobrara-<br>Carlile<br>Greenhorn | Upper<br>Colorado          | 1st white specks                             | Upper<br>Colorado | 1st white specks                             |           |       |  |
|                     |             |                                                  | Blackleaf                    | Mowry Shale                       | Lower<br>Colorado          | 2nd white specks<br>base of fish scales zone | Lower<br>Colorado | 2nd white specks<br>base of fish scales zone |           |       |  |
|                     |             |                                                  |                              | Bow Island Newcastle              |                            | Bow Island Viking                            |                   | Viking                                       |           |       |  |
|                     |             |                                                  |                              | Skull Creek Shale                 |                            | basal Colorado                               |                   | Joli Fou                                     |           |       |  |
|                     | Dakota Silt |                                                  |                              |                                   |                            |                                              |                   |                                              |           |       |  |
|                     | Lower       | Dakota Sandstone<br>(1st Cat Creek/Flood Member) |                              |                                   | Mannville (Blairmore)      |                                              |                   |                                              | Mannville | Upper |  |
|                     |             |                                                  |                              |                                   |                            |                                              |                   |                                              |           |       |  |
|                     |             | Kootenai Formation                               | Fuson                        |                                   |                            | glauconitic sandstone                        |                   |                                              |           | Lower |  |
|                     |             |                                                  | calcareous                   |                                   |                            | ostracod zone                                |                   |                                              |           |       |  |
|                     |             |                                                  |                              |                                   |                            | calcareous                                   |                   |                                              |           |       |  |
| Moulton<br>Sunburst |             |                                                  | basal Blairmore              |                                   |                            |                                              |                   |                                              |           |       |  |
| Cutbank             |             |                                                  | medial                       |                                   |                            |                                              |                   |                                              |           |       |  |
|                     |             |                                                  | Moulton<br>Sunburst<br>Taber |                                   |                            | Cutbank                                      |                   |                                              |           |       |  |
| Jurassic            | Upper       | Ellis Group                                      | Morrison                     |                                   | Ellis Group                | Swift                                        |                   | Vanguard                                     | J-1       |       |  |
|                     |             |                                                  | Swift                        |                                   |                            | Rierdon                                      |                   |                                              |           |       |  |
|                     |             |                                                  | Rierdon                      |                                   |                            | Sawtooth<br>Piper                            |                   |                                              |           |       |  |
|                     | Middle      |                                                  | Sawtooth                     |                                   |                            |                                              |                   | Shaunavon                                    | J-2       |       |  |
| Lower               |             |                                                  |                              |                                   |                            |                                              |                   | Gravelbourg J-3<br>Watrous J-4               |           |       |  |
| Triassic            |             |                                                  |                              |                                   |                            |                                              |                   |                                              |           |       |  |
| Permian             |             |                                                  |                              |                                   |                            |                                              |                   |                                              |           |       |  |
| Pennsylvanian       |             |                                                  |                              |                                   |                            |                                              |                   |                                              |           |       |  |
| Mississippian       |             | Madison Group                                    | Sun River                    |                                   | Rundle Group               | Turner Valley                                | Upper             | Mission Canyon                               |           |       |  |
|                     |             |                                                  | Mission Canyon               |                                   |                            | Middle                                       |                   |                                              |           |       |  |
|                     |             |                                                  | Lodgepole                    |                                   |                            | Elkton                                       |                   |                                              |           |       |  |
|                     |             |                                                  |                              |                                   |                            | Shunda                                       | Locally Undiff.   |                                              |           |       |  |
|                     |             |                                                  |                              |                                   |                            | Pekisko                                      |                   |                                              |           |       |  |
|                     |             |                                                  |                              |                                   |                            | Banff                                        |                   |                                              |           |       |  |
|                     |             | Bakken                                           |                              | Exshaw                            |                            |                                              |                   |                                              |           |       |  |
| Devonian            |             |                                                  |                              |                                   |                            |                                              |                   |                                              |           |       |  |
|                     |             | Three Forks Formation                            |                              |                                   | Palliser                   |                                              |                   | Devonian<br>Undivided                        |           |       |  |
|                     |             | Pottlatch Formation                              |                              |                                   | Alexo Formation            |                                              |                   |                                              |           |       |  |
|                     |             | Nisku                                            |                              |                                   | Birdbear                   |                                              |                   |                                              |           |       |  |
|                     |             | Duperow                                          |                              |                                   | Fairholme Group            |                                              |                   |                                              |           |       |  |
|                     |             | Souris River                                     |                              |                                   |                            |                                              |                   |                                              |           |       |  |
| Cambrian            |             | Red Lion                                         |                              |                                   | Purcell Group              |                                              |                   | Cambrian<br>Undivided                        |           |       |  |
|                     |             | Pilgrim                                          |                              |                                   |                            |                                              |                   |                                              |           |       |  |
|                     |             | Cambrian Shale<br>Undivided                      |                              |                                   |                            |                                              |                   |                                              |           |       |  |
|                     |             | Flathead                                         |                              |                                   |                            |                                              |                   |                                              |           |       |  |
| Precambrian         |             | Belt                                             |                              |                                   | Basement                   |                                              |                   | Basement                                     |           |       |  |

Figure 118. Geologic columns for Sweetgrass Arch area, Montana, and southern Alberta and Saskatchewan, Canada. After [Dolson et al. \(1993\)](#).

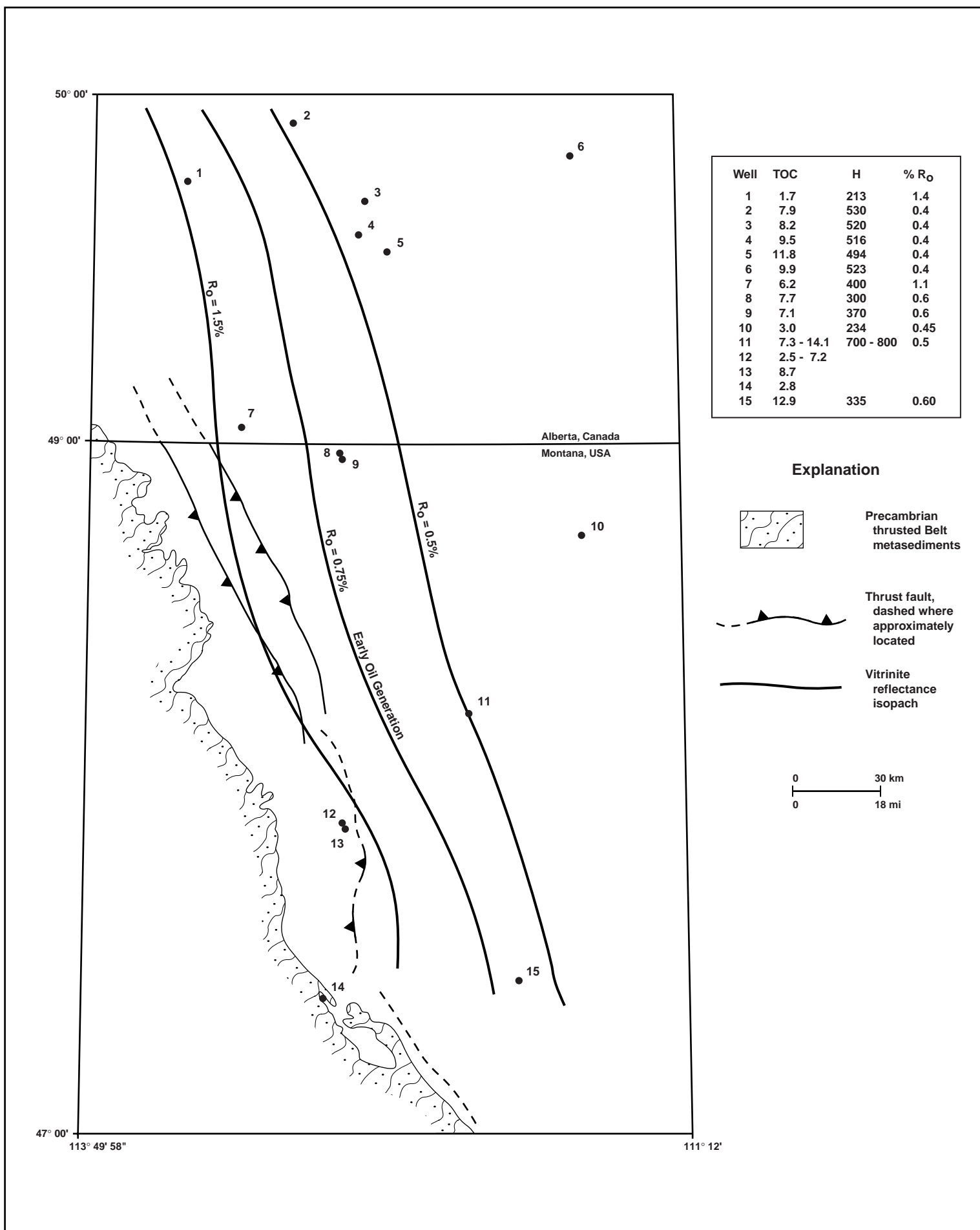


Figure 119. Map of Bakken Formation total organic carbon (TOC) and maturation levels (hydrogen, H, and vitrinite reflectance, % R<sub>O</sub>). Thermally mature source strata are located on the extreme western margin of the Sweetgrass Arch and within the footwall to the thrust belt in Montana and Alberta. After [Dolson et al \(1993\)](#).

## WASATCH PLATEAU

### GEOLOGIC SETTING

The Wasatch Plateau is an 80 mi long by 25 mi wide uplift west of the San Rafael Swell in east-central Utah, within parts of Sanpete, Sevier, Emery and Carbon Counties, and lies sandwiched between Sanpete Valley to the west and Castle Valley to the east ([Figures 120 and 121](#)). Structural features west of the Plateau include the Gunnison Plateau and Wasatch Monocline ([Figure 121](#)). The Wasatch Plateau forms part of the central Utah transition zone, between the Colorado Plateau to the east and the Basin and Range province to the west.

The Plateau's history begins with Cretaceous synorogenic deposition of clastic sediments in a foreland basin east of the Cordillera. On the western periphery of the basin, local deposits of deltaic and paludal sediments alternated with deepwater mudstones deposited during several transgressive cycles ([Figure 122](#)). Eastward thrusting and uplift probably began during the late Jurassic-early Eocene Sevier Orogeny ([Neuhauser, 1988](#)). Diapiric movements and extensional faulting occurred during the Cenozoic era. [Figure 121](#) shows fault structure for the area.

Exposures of Quaternary alluvium, Tertiary sandstones and limestones, and Upper Cretaceous Mesaverde Group sandstones, shales and coalbeds occur atop the Plateau. [Figures 122 and 123](#) show the area's stratigraphy.

### HYDROCARBON PRODUCTION

Oil and gas production in the Wasatch Plateau occurs mostly from Cretaceous Ferron sandstones east of the Joe's Valley Graben and west of the Ferron outcrop ([Tripp, 1996](#)). The Cretaceous Dakota Group and Permian Kaibab Formation have had some minor production as well. The fields along the Plateau have produced over 158 BCFG and 132 MBO since 1951.

On the eastern margin of the plateau, recent coalbed methane production from Ferron coals in Drunkards Wash Field (discovered in 1992) has sparked renewed interest in the area ([Lamarre and Burns, 1997](#)). Cumulative production including coalbed methane exceeds 224 BCFG.

Production on the Wasatch Plateau has generally been from structural traps, probably enhanced by tectonic fracturing ([Tripp, 1990](#)).

### EVIDENCE FOR BASIN-CENTERED GAS

Not enough evidence exists to determine if an overpressure cell encompassing the Cretaceous rocks occurs at deeper drilling depths within the plateau. Production does occur from gas fields along the eastern plateau margin, but pressure gradients are very low (significant underpressure) and only range from 0.21 to 0.27 psi/ft. Also, the Ferron field shows down-dip water flows (recorded in Northwest Prod. Co. #1 Federal, NENE 29-19S-7E), which indicates underpressuring and a probable gas-water contact at depth. Additionally, drillstem tests in the vicinity of the plateau recovered water, indicating normal to underpressuring in the lower Cretaceous sediments. Most wells showing water are in close proximity to known mapped faults ([Tripp, 1989](#)). The high degree of tectonism and associated fracturing of the rocks may allow water to flow upward from the Paleozoic section or downward from Tertiary and Cretaceous rocks along the fault zones. If a "gas kitchen" once existed in this area, faulting may have breached it.

Exploration the central part of the Plateau has been rare and many townships remain untested. However, in 1996 Cimarron Energy Corporation re-entered a 20,505 ft deep test well (Hanson Oil Corp.'s Maroni #1AX, 14-15S-3E); Cimarron completed two sidetracks within Tununk Shale at depths of 11,772 and 11,840 ft. Cumulative production through June of 1999 was 369 BO and 425 MCF for this undesignated field ([Utah Div. of Oil, Gas and Mining, 1999](#)). This significant show indicates a fractured shale play probably occurs on the Plateau.

## KEY ACCUMULATION PARAMETERS

### Identification

Great Basin/Colorado Plateau, basin-centered gas play in deeper Cretaceous Rocks, Wasatch Plateau

### Geologic Characterization of Accumulation:

- a. Source/reservoir** Tununk and Bluegate Shale members of Mancos Shale and shale of the Dakota Group; Ferron and Emery Sandstone Members of Mancos Shale; Morrison Sandstones
- b. Total Organic Carbons (TOCs)**
- c. Thermal maturity**  $R_o$  values for Ferron coals at Drunkards Wash Field (T14 to 15S, R9 to 10E) reportedly average 0.69% (Lamarre and Burns, 1997). Blackhawk coals from mines in the Wasatch Plateau (T12 to 25S, R1 to 10E) (Bodily et al., 1991) are high volatile bituminous (HVBc) in rank; this would correlate with an  $R_o$  of 0.60 – 0.78%. Vitrinite reflectance data for coals within the sandstone member in the Emery Coal Field (T14S to 22S, R6 to 9E) range from 0.52 to 0.63%. Other coals within the field have measured values up to 0.74% (Hucka et al., 1997); these values are probably too low for a basin-centered gas accumulation.
- d. Oil or gas prone** Primarily gas prone, type III and type II kerogens.
- e. Overall basin maturity** Fair to moderate. The extreme western edge of the plateau may be immature.
- f. Age and lithologies** Cretaceous shales, coals, delta plain and alluvial sandstones. Dakota sandstone is conglomeratic.
- g. Rock extent/quality** The Ferron and Emery extend over plateau. Sparse drilling of Dakota and Morrison renders the regional extent unknown. Tununk and Bluegate Shales are regionally extensive. Individual Ferron coals are laterally discontinuous.
- h. Potential reservoirs** Best reservoir rock occurs within channel facies.
- i. Major traps/seals** Mostly structural with some stratigraphic. The Cretaceous Tununk Shale separating the Ferron and Dakota Sandstones and the Bluegate Shale above and below the Emery and Ferron act as seals. Interbedded shales within the sandstones may form seals.
- j. Petroleum generation/migration models** In-situ generation and long distance migration. Geothermal gradient ranges from 23 to 29° C per km.
- k. Depth ranges** 8,500 to 12,000 ft

**Production and Drilling  
Characteristics:**

- l. Pressure gradients** Subnormal pressure gradients range from .21 to .27 psi/ft. Some drillstem tests recovered water, indicating normal to underpressure in western portions of the plateau. Insufficient data exists to determine if an overpressure cell in the Cretaceous rocks exists at deeper drilling depths within the plateau.

- a. Important fields/reservoirs** Clear Creek (Ferron Ss), Drunkards Wash (Ferron coals), Flat Canyon (Ferron and Dakota ss), and Ferron fields (Ferron Ss). Joe's Valley fields are discussed in the San Rafael Swell section of this report.
- b. Cumulative production** Production has come from fields in faulted anticlinal structures along the east flank of the plateau. Clear Creek: 114.4 BCF; Drunkards Wash: 66 BCF; Flat Canyon: 1.4 BCF and 317 bbls; and Ferron: 10.2 BCF and 38,770 bbls (Tripp, 1991a, 1991b; 1993a).

**Economic  
Characteristics:**

- a. Inert gas content** Not a problem. The Ferron gas is 90-98% methane with a Btu range from 990-1129. Flat Canyon Field Dakota gas is 1107 Btu with a methane content of 91% (Tripp, 1991b, 1993c). Ferron coalbed methane had a Btu of 987-1000 with methane concentrations from 95.8-98.3% and carbon dioxide contents of 0.7-0.30% (Lamarre and Burns, 1997). Tests of Paleozoic rocks on the Gordon Anticline, located east of the Plateau, have encountered CO<sub>2</sub> from the Moenkopi Formation and the Coconino sandstone (Tripp, 1990).
- b. Recovery** low
- c. Pipeline infrastructure** Limited.
- d. Exploration maturity relative to other basins**
- e. Sediment consolidation** Well indurated.
- f. Porosity/completion problems** Formation damage due to swelling clays may reduce or prevent production if appropriate drilling and completion fluids are not utilized.
- g. Permeability** Ferron permeability ranges from .05 to .14 md. Permeability for the Dakota, Morrison and Emery are unknown.
- h. Porosity** Ferron porosity ranges from 8 to 17%; Dakota porosity at Flat Canyon Field averages 4% (Tripp, 1989; 1991a; 1993b; 1993c).

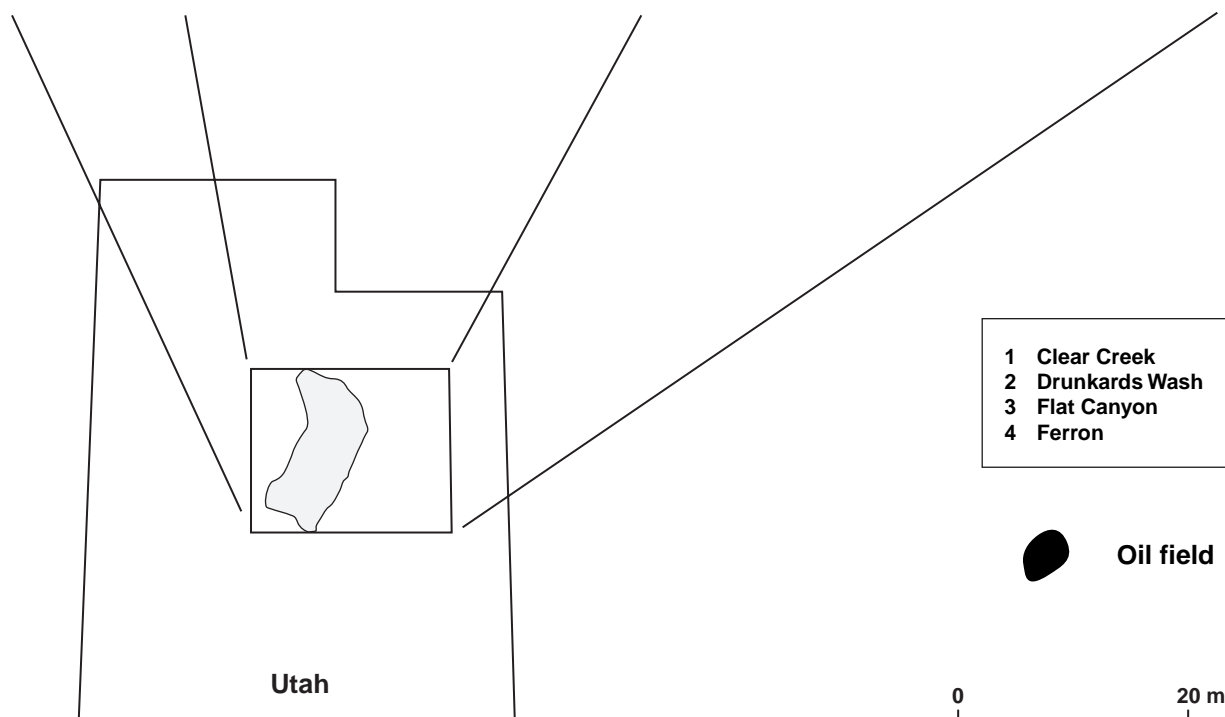
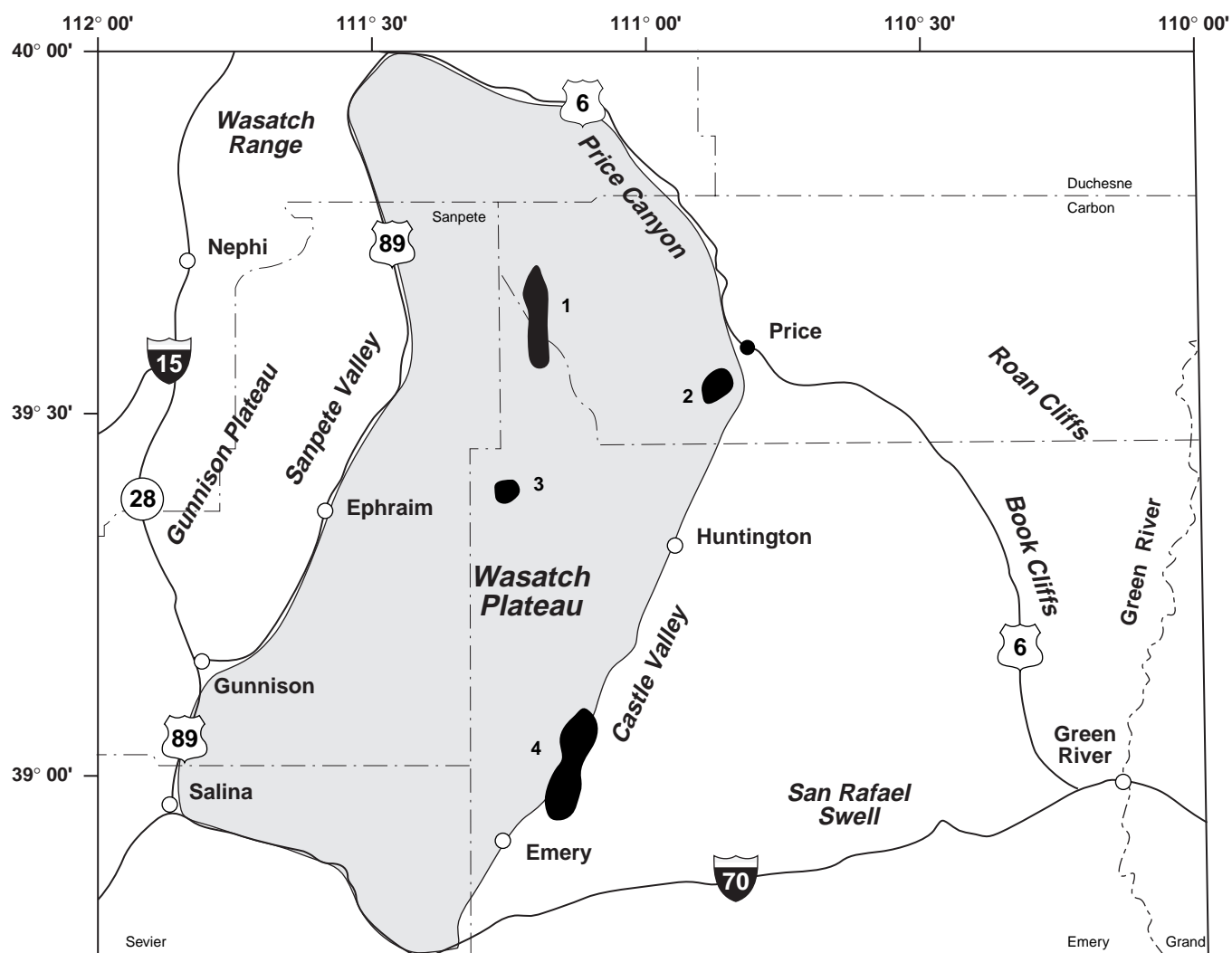


Figure 120. Location map of Wasatch Plateau, Utah. After [Franczyk and Pitman \(1991\)](#), and [Hill and Bereskin \(1993\)](#).

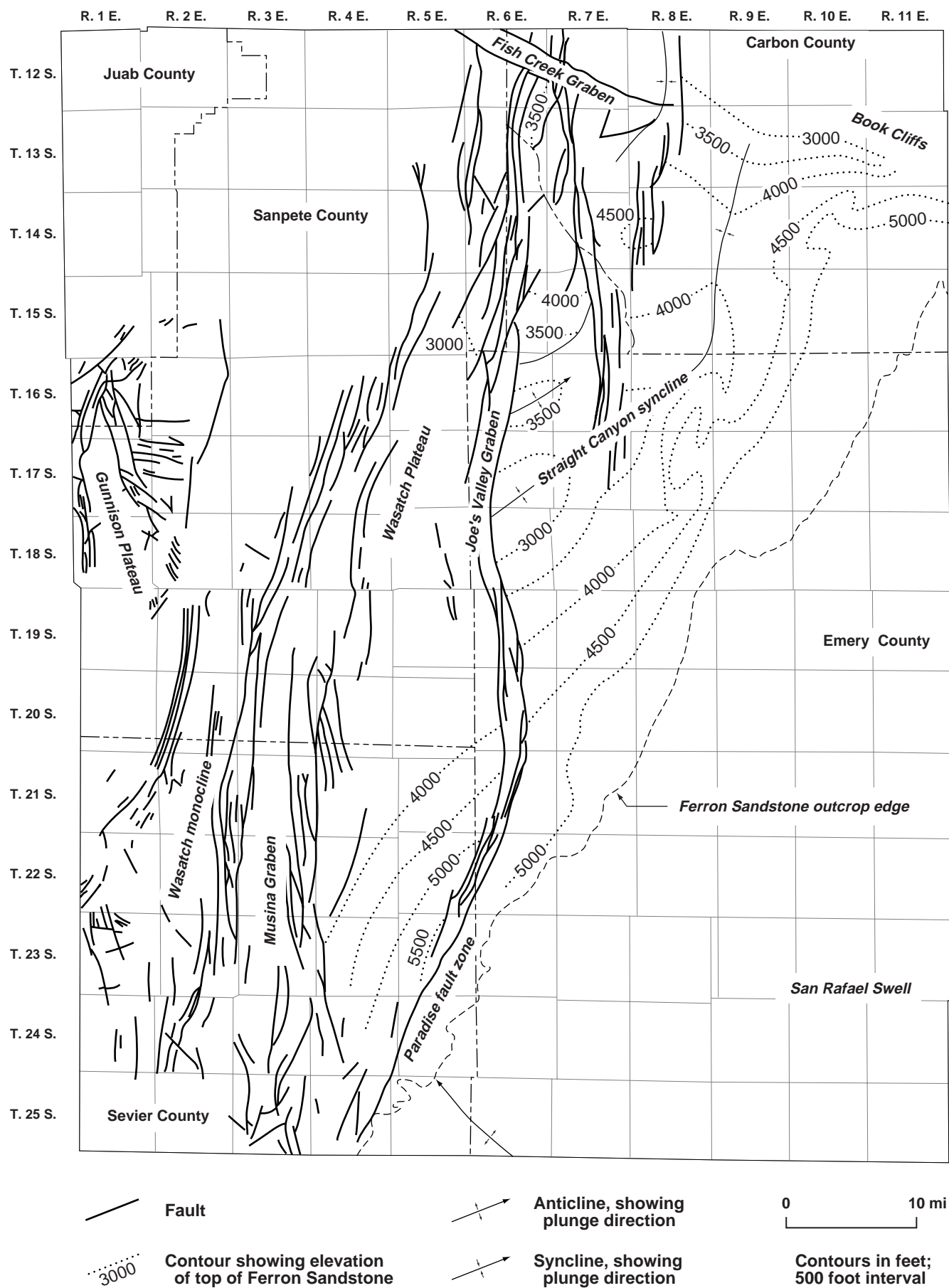


Figure 121. Structure map of the Wasatch Plateau area, Utah, showing the elevation of the top of the Ferron Sandstone. After [Tripp \(1989\)](#).

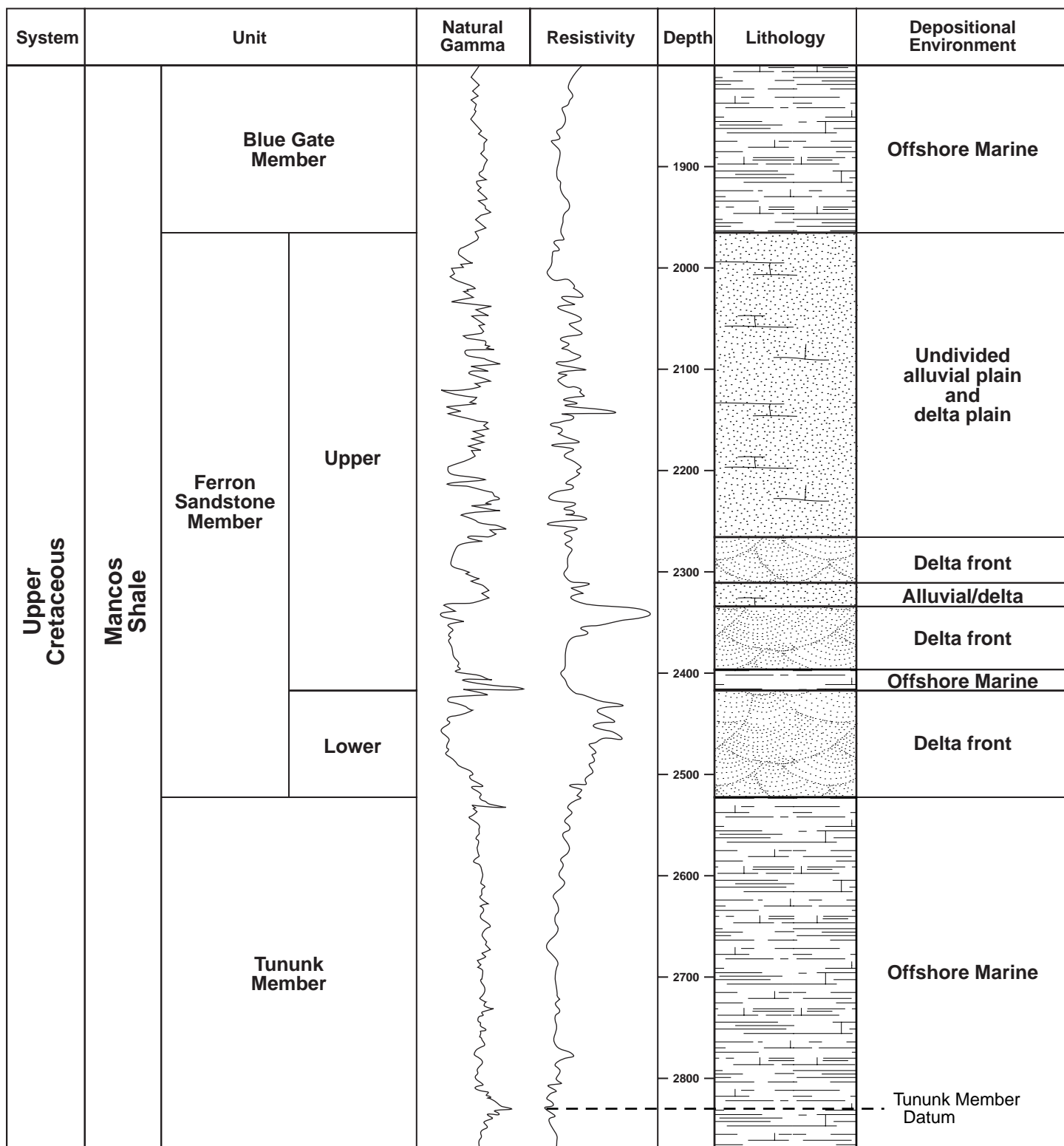


Figure 122. Reference log for the Ferron Sandstone Member from the Willard Pease State of Utah No. 1-Q well (Section 16, T22S, R5E). After [Ryer and McPhillips \(1983\)](#).

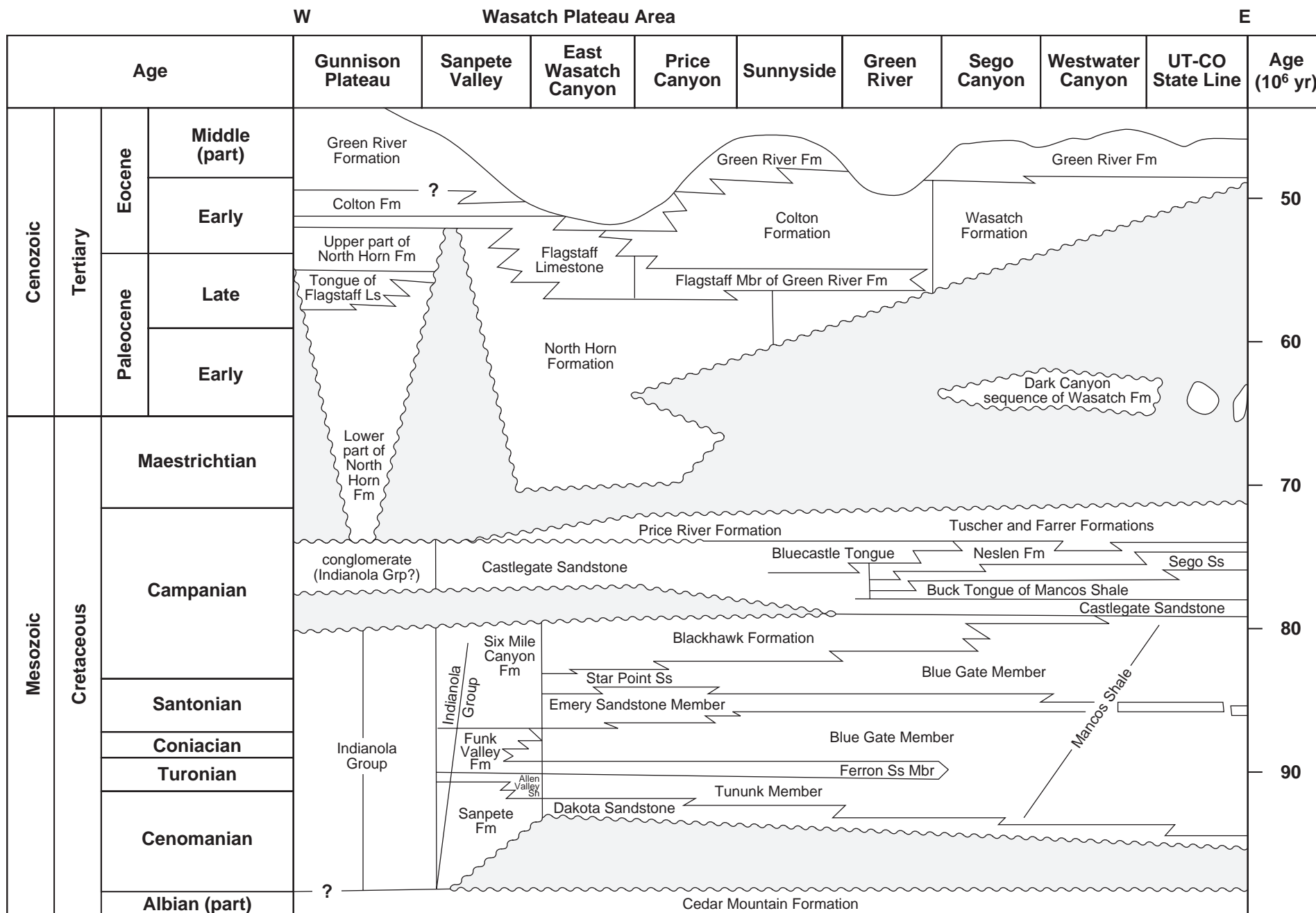


Figure 123. Stratigraphic column and cross section for Wasatch Plateau and vicinity, northeastern Utah. After [Franczyk and Pitman \(1991\)](#).

## WESTERN WASHINGTON (WILLAMETTE-PUGET SOUND TROUGH)

### GEOLOGIC SETTING

The Willamette-Puget Sound trough extends south from Vancouver Island in British Columbia 490 mi to the Klamath Mountains in southwestern Oregon (Figure 124) (Johnson et al., 1997; Johnson and Tennyson, 1996). In northern Washington, the Olympic Mountains interrupt this general trend. The Cascade Range forms the eastern boundary. The trough extends 50 to 140 mi offshore to an approximate depth of 3,300 ft on the continental shelf (Armentrout and Suck, 1985). Within the trough are the Tyee, South Willamette, North Willamette, Nehelem, and Seattle basins. West of the main part of the trough and adjacent to the Pacific coastline are four subbasins: Coos Bay, Newport, Astoria, and Willapa (Armentrout and Suck, 1985; Johnson et al., 1997; and Johnson and Tennyson, 1996).

Around the northern, northeastern and southern margins, accreted terranes of Mesozoic sedimentary, volcanic and metamorphic rocks crop out and may underlie the eastern part of the trough (Johnson et al., 1997; Johnson and Tennyson, 1996). Up to 20,000 feet of Cenozoic forearc sediments overlie pre-Tertiary igneous and metamorphic basement. Figure 125 shows the stratigraphy for various play areas in western Washington. Depositional environments included fluvial, fan-delta, delta, shallow-marine, continental-slope and submarine fan (Johnson et al., 1997; Johnson and Tennyson, 1996).

Oligocene to Pliocene uplift occurred simultaneously with subsidence of local depositional areas. Late Miocene basalt flows flooded the Columbia River and northern Willamette Valleys, and associated intrusive activity occurred concurrently. The Columbia River deposited deltaic and shallow-marine sediments in southwestern Washington and northwestern Oregon (Astoria and Montesano Formations) from Miocene to Pliocene time (Figure 125). Subduction along the continental margin during the Eocene caused extensive folding, faulting, uplift and subsidence (Johnson et al., 1997; Johnson and Tennyson, 1996).

Conventional sandstone reservoir candidates include the shallow marine Spencer and Cowlitz Formations, the deltaic to submarine fan Tyee Formation, the fluvial Chuckanut Formation, and the deltaic Puget Group.

### HYDROCARBON PRODUCTION

Many oil and gas seeps occur along the Washington coast, and hydrocarbon exploration began in 1881. More than 500 wells have been drilled in the Pacific Northwest, but most are less than 5,000 feet deep. The only commercially productive hydrocarbon reservoir in the Willamette-Puget Sound trough is Mist gas field, a faulted, structural trap located northwest of Portland, Oregon (Armentrout and Suck, 1985) (Figure 124). Since its discovery in 1979, Mist field has produced over 70 BCFG from sandstones in the Eocene Cowlitz Formation.

Before discovery of the Mist gas field, the only hydrocarbon production in the region came from the Bellingham-Watcom County coal fields, the Rattlesnake Hills field near Yakima in the Columbia Plateau, and the Grays Harbor-Ocean City field, which to date has produced about 12,000 BO plus some associated gas (McFarland, 1981; Armentrout and Suck, 1985) (Figure 124).

## EVIDENCE FOR BASIN-CENTERED GAS

In the northern Willamette basin, the lower Cowlitz Formation strata entered the oil-generating window about 33 Ma ([Armentrout and Suek, 1985](#)). Upper Cowlitz rocks entered the generation window at 3 Ma. Present-day geothermal gradients average 15 °F per 1,000 ft; thus, present-day reservoir temperatures should support gas generation at depths exceeding 7,000 ft. This depth is slightly shallower than the 8,000 ft depth of the overpressured envelope. Favorable parameters exist elsewhere in the trough that suggest in-situ gas generation is taking place.

Eocene coals and carbonaceous shales are potential gas-prone source rocks. Total organic carbon (TOC) content in the Willamette basin varies from 0.65% to 7.22% for marine shales and siltstones of the Cowlitz Formation; interbedded coals have up to 55% TOC ([Johnson and Tennyson, 1996](#); [Johnson et al., 1997](#)). Vitrinite reflectance values range from 0.24 to 4.01 across the basin. High values result from contact metamorphism near igneous intrusions along the Cascades. Projected temperatures within the hydrocarbon generation window range from 90 to 140 °C ([Armentrout and Suek, 1985](#)).

The shales encasing the Mist field reservoir are thermally immature, with Ro values less than 0.4% ([Armentrout and Suek, 1985](#)). The gas within the reservoir probably generated deep in the basin and migrated updip into the shallow structural trap.

## KEY ACCUMULATION PARAMETERS

### Identification

Western Washington Province, Willamette-Puget Sound Trough, basin-centered gas play

### Geologic Characterization of Accumulation:

- |                                                 |                                                                                                                                                                                                                                                                                                                                        |
|-------------------------------------------------|----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <b>a. Source/reservoir</b>                      | Interval includes Eocene Cowlitz, Puget Group, Raging River, Crescent formations and equivalents.                                                                                                                                                                                                                                      |
| <b>b. Total Organic Carbons (TOCs)</b>          | Range from 0.5 to 7.22% in the middle to upper Eocene marine mudstones in the conventional Cowlitz-Spencer gas play area of the Southern Puget lowlands ( <a href="#">Johnson et al., 1997</a> ). Coals show up to 55% TOCs in the play area ( <a href="#">Walsh and Lingley, 1991</a> ).                                              |
| <b>c. Thermal maturity</b>                      | $R_o$ 0.24 - 4.01 ( <a href="#">Armentrout and Suek, 1985</a> ; <a href="#">Walsh and Lingley, 1991</a> )                                                                                                                                                                                                                              |
| <b>d. Oil or gas prone</b>                      | Gas prone; almost exclusively type III kerogens.                                                                                                                                                                                                                                                                                       |
| <b>e. Overall basin maturity</b>                | Maturation levels are moderate ( $R_o$ ranges from 0.24 to 4.01) and increase east of the trough toward the crest of the Cascade Range.                                                                                                                                                                                                |
| <b>f. Age and lithologies</b>                   | Eocene arkosic sands, coals, siltstones and shales.                                                                                                                                                                                                                                                                                    |
| <b>g. Rock extent/quality</b>                   | Probable basin-wide source and reservoir-rock distribution. Rock quality is unknown except from a few wells and from outcrops around basin margins. Expected reservoir quality varies depending on clay content, zeolite alteration, and interbedded shales and coals.                                                                 |
| <b>h. Potential reservoirs</b>                  | Gas-bearing reservoirs occur in Eocene or possibly older rocks ( <a href="#">Johnson et al., 1997</a> ); very few conventional reservoirs exist; structurally trapped Mist field in northern Oregon has produced more than 70 BCFG.                                                                                                    |
| <b>i. Major traps/seals</b>                     | Interbedded Eocene-age shales, siltstones and coals; diagenetic barriers might also be expected within micaceous and arkosic sands.                                                                                                                                                                                                    |
| <b>j. Petroleum generation/migration models</b> | Primarily in-situ generation, but fracture zones offer the possibility of long distance migration of gases from shales and coals. Hydrocarbon generation is probably ongoing at depths below 7,000 ft. Low present-day geothermal gradients occur with an estimated 12.5° F per 1000 ft ( <a href="#">Armentrout and Suek, 1985</a> ). |
| <b>k. Depth ranges</b>                          | 8,000 to more than 13,000 ft.                                                                                                                                                                                                                                                                                                          |
| <b>l. Pressure gradients</b>                    | Overpressured intervals are referenced in <a href="#">Walsh and Lingley (1991)</a> and <a href="#">Johnson et al. (1997)</a> .                                                                                                                                                                                                         |

**Production and Drilling  
Characteristics:**

- |                                       |                                                                                                                                                                                                                      |
|---------------------------------------|----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <b>a. Important fields/reservoirs</b> | unknown                                                                                                                                                                                                              |
| <b>b. Cumulative production</b>       | The only existing production comes from a conventional structural trap at the Mist field (discovered in 1979) that has produced 70 BCFG from Eocene Cowlitz Formation ( <a href="#">Armentrout and Suek, 1985</a> ). |

**Economic  
Characteristics:**

- |                                                         |                                                                                                                                                                                                                                                                                                                |
|---------------------------------------------------------|----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <b>a. Inert gas content</b>                             | Gases from the Mist field contain from 2.7 to 5.3% nitrogen ( <a href="#">Armentrout and Suek, 1985</a> ), with traces of CO <sub>2</sub> . Hydrocarbon composition exceeded 99.9% methane. Higher Btu and lower inerts content are expected for gases thermally generated within the continuous accumulation. |
| <b>b. Recovery</b>                                      | Recoveries may vary depending upon permeability, porosity and depth; diagenetic alteration may increase with depth.                                                                                                                                                                                            |
| <b>c. Pipeline infrastructure</b>                       | poor                                                                                                                                                                                                                                                                                                           |
| <b>d. Exploration maturity relative to other basins</b> |                                                                                                                                                                                                                                                                                                                |
| <b>e. Sediment consolidation</b>                        | Probably moderate to good.                                                                                                                                                                                                                                                                                     |
| <b>f. Porosity/completion problems</b>                  | Shales, clay and mica-rich arkosic sands have high alteration potential; possible swelling clays. Migrating fines may be a problem and average porosities may be highly variable. Shales, siltstones and coals are interbedded with sands.                                                                     |
| <b>g. Permeability</b>                                  | Permeability declines with depth ( <a href="#">Walsh and Lingley, 1991</a> )                                                                                                                                                                                                                                   |
| <b>h. Porosity</b>                                      | Cowlitz reservoir strata in the Mist field area show porosities from 16 to 41%. Porosity declines with depth ( <a href="#">Walsh and Lingley, 1991</a> )                                                                                                                                                       |

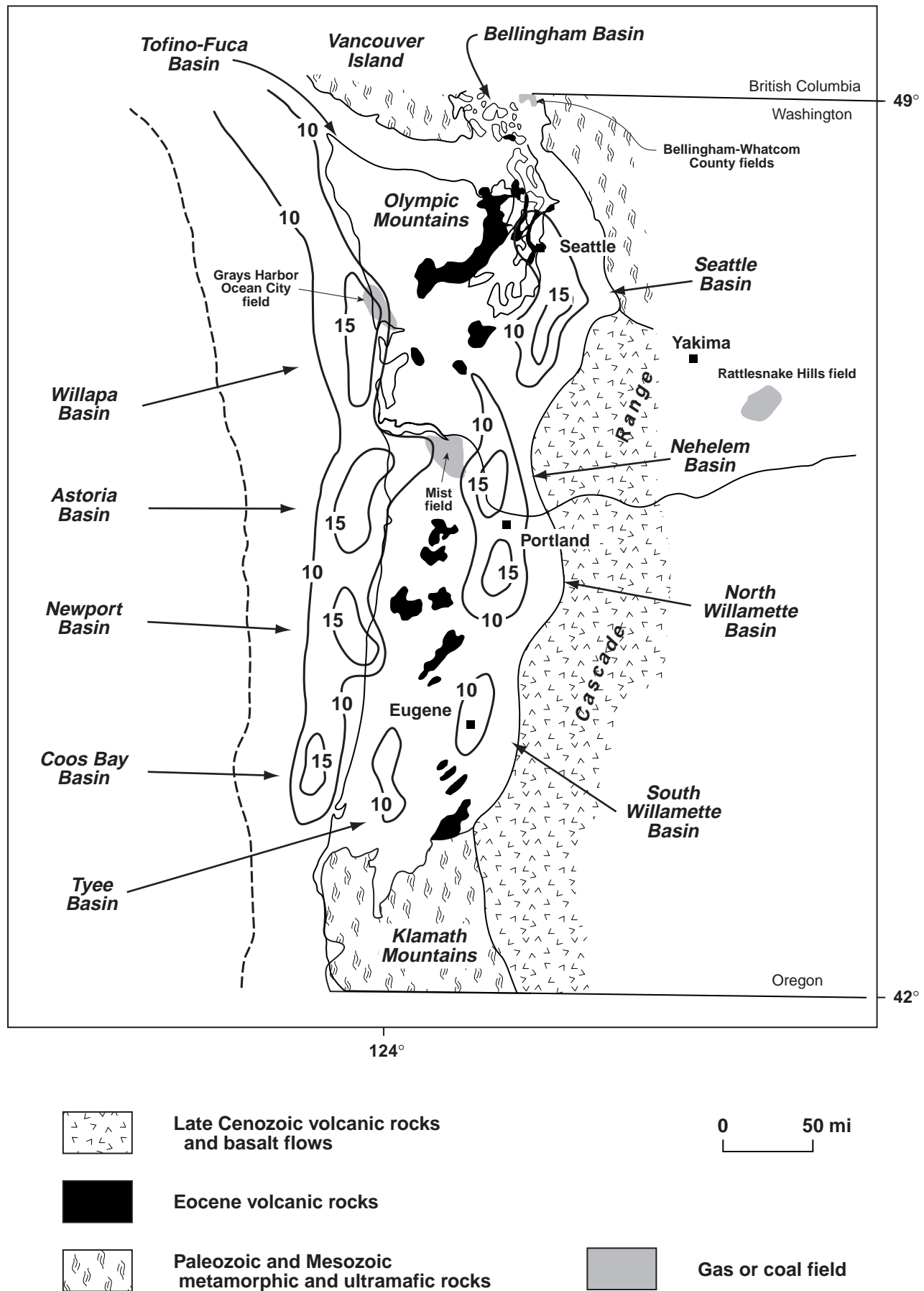


Figure 124. Location map of Cenozoic basins of western Washington and Oregon. Isopach contours are in thousands of feet. After [Armentrout and Suek \(1985\)](#).

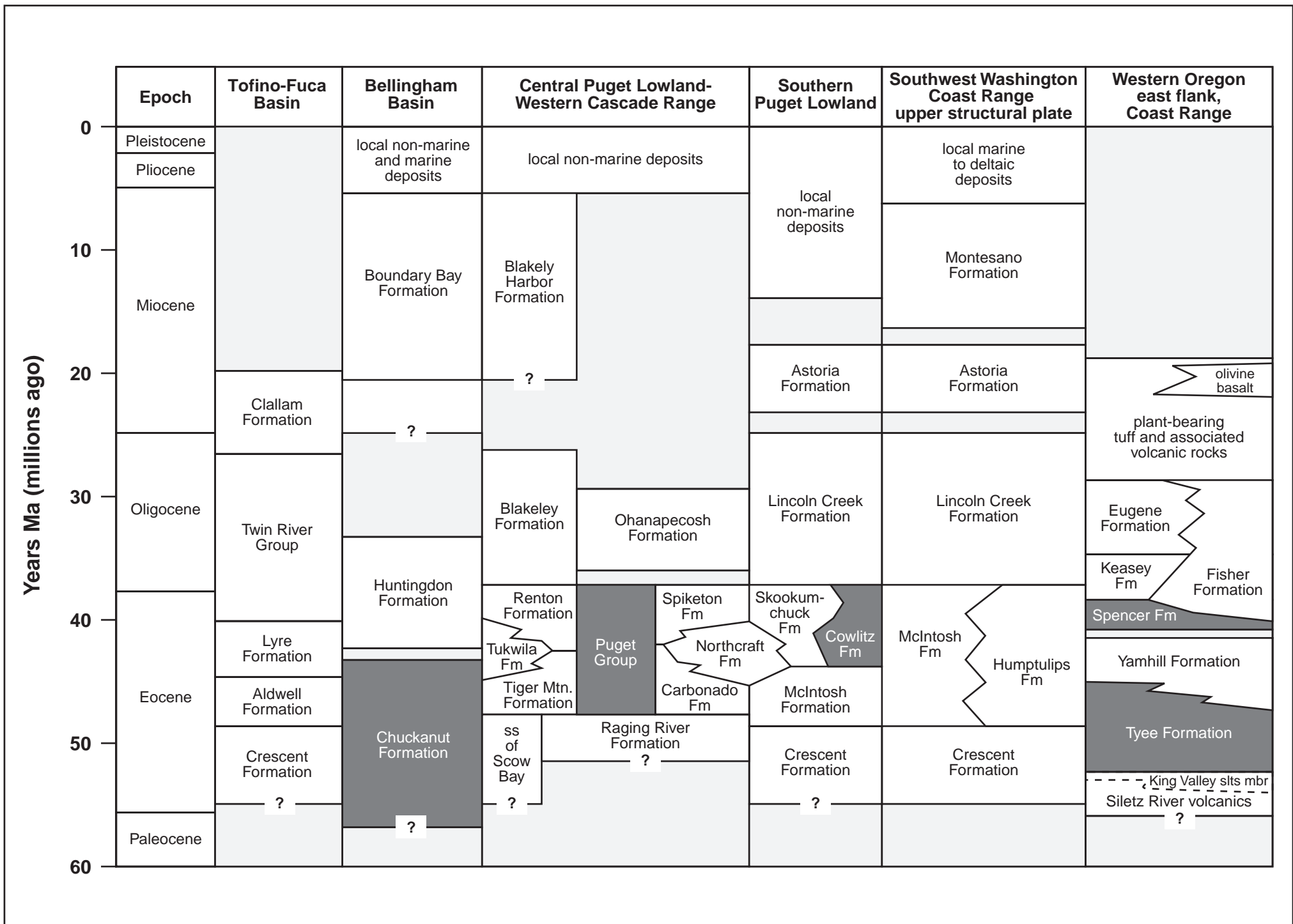


Figure 125. Stratigraphic column for western Washington petroleum-play areas. Shaded intervals indicate occurrences of erosion or no deposition. Darkened formations highlight reservoir candidates mentioned in report. After [Braislin et al. \(1971\)](#), [Armentrout and Suek \(1985\)](#), and [Johnson et al. \(1997\)](#).

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## **APPENDIX I:**

### **PHASE II ABSTRACTS**

#### **Potential for a Basin-Center Gas Accumulation in the Albuquerque Basin, New Mexico**

The potential that a basin-center or continuous-type gas accumulation is present in the Albuquerque Basin in central New Mexico was investigated. The Albuquerque Basin is one of the many rift basins that make up the Rio Grand Rift system, an area of active extension from Oligocene to recent time. The basin is significantly different from other Rocky Mountain basins that contain basin-centered gas accumulation because it is actively subsiding and is at near maximum burial and heating conditions at the present time. Burial reconstructions suggest that Cretaceous-age source rocks began to generate gas in the deeper parts of the basin about 20 million years ago and are still generating large amounts of gas. High mud weights are typically used while drilling the Cretaceous interval in the deeper areas of the basin suggesting some degree of overpressuring. Gas shows are commonly reported while drilling through the Cretaceous interval; however, attempts to complete gas wells in the Cretaceous have resulted in sub-economic quantities of gas, primarily because of low permeability. Little water has been reported. All of these characteristics suggest that a basin-center gas accumulation of some degree is present in the Albuquerque Basin.

#### **Is There a Basin-Center Gas Accumulation In the Deep Anadarko Basin?**

Well data, formation test results and published studies of abnormal pressures, methane isotopes and thermal maturity were reviewed to evaluate the possibility that a basin-center gas accumulation might exist within the regionally overpressured Mississippian and Pennsylvanian-age Atoka, Morrow and Springer Groups or in the Mississippian and Devonian-age Woodford Shale in the central Anadarko basin, Oklahoma.

The Woodford Shale is a laterally extensive, organic-rich source rock which has passed completely into the gas generation window in the deepest parts of the basin, but it does not appear to have developed overpressures on a regional scale. A review of drilling mud weights and pressure data indicate that the Woodford Shale-Hunton Group interval has generally been drilled with 9 to 10.5 ppg mud and appears to be normally to subnormally pressured throughout most of the central basin. The underlying Hunton Group contains high permeability zones which frequently produce subnormally or normally pressured salt water. Hydrocarbons expelled from the Woodford Shale may have migrated downward into the Hunton aquifer and then moved laterally into structural and stratigraphic traps. Two isolated overpressured compartments were identified where high mud weights and unusual casing designs were used for the Woodford section. These appear to be uplifted fault blocks where structural juxtaposition of the Woodford Shale and overpressured Springer shales may have locally modified the typical plumbing system. The Woodford Shale does not appear to fit the basin-center gas model on a regional scale.

The Atoka-Morrow-Springer section has many characteristics of known basin-center gas accumulations, including mature, gas-prone source rocks, temperatures greater than 200° F, severe overpressures, tight sandstone reservoirs, and extensive gas production. However, formation test data and published descriptions of known gas fields reveal numerous examples of gas-water contacts and water production within the overpressured section. Most commercial gas accumulations have been found in traditional structural and/or stratigraphic traps, but many of the known gas reservoirs are water-saturated below distinct gas-water contacts. The available porosity in the reservoirs was apparently not fully charged with gas. Perhaps the source rocks were not rich enough, or perhaps they cooled down and ceased gas expulsion too early, so that the porosity available in the numerous sandstones was not completely gas-saturated. Depending on current interpretations of just how much moveable water is allowable in a 'continuous-type' gas accumulation, the overpressured Atoka-Morrow-Springer section does not quite fit the basin-center gas model on a regional scale.

Several reservoir zones within the deep Anadarko Basin may be completely gas-saturated on a local scale. Well data and formation tests at North Broxton Field (T. 6 N., R. 12 W., Caddo County, Oklahoma) and Elk City Field (T. 10 N., R. 20 - 21 W., Washita and Beckham Counties, Oklahoma) indicate severe overpressures, high temperatures, prolific gas production and almost no water production from the Springer section at depths of approximately 18,500 to 20,500 ft. Further study of formation test results and detailed log analyses are recommended to determine if the deep Springer section might contain a small-scale basin-center gas accumulation.

### **Is There a Basin-Center Gas Accumulation in the Columbia Basin (Pasco Basin), Central Washington?**

Well data, vitrinite analyses and previous geologic literature were examined to determine if the sparsely drilled Pasco basin in central Washington might contain a basin-center gas accumulation similar to those found in several Rocky Mountain basins. The limited geologic data available to the public show that many pre-requisites are present, including abnormal pressure gradients, thermally mature source rocks, high temperatures, abundant shows of natural gas, and tight sandstone reservoirs. However the results of twenty formation tests conducted in several deep exploration wells indicate that water-bearing zones have been encountered frequently. With the exception of a 1,850 ft thick section in the Roslyn Formation in the Shell Yakima Mineral Co. No. 1-33 well which might be gas-saturated, the test data indicate widespread occurrences of gassy formation water, and several zones which produced water at high rates (> 50 barrels of water per day). The sedimentary section does not appear to be extensively gas-saturated.

The Pasco basin appears to be almost, but not quite a basin-center gas accumulation, with adequate temperatures, thermally mature, gas-prone source rocks, overpressure and gas shows. But the formation test results indicate too much water and not enough gas to completely match the definition. The volume of gas expelled from the source rocks may have been inadequate to effectively de-water the reservoir section. A Miocene-age regional hydrothermal event may have altered the plumbing of the basin.

### **Is There a Basin-Center Gas Accumulation in Cotton Valley Group Sandstones, Gulf Coast Basin, USA?**

In 1995 the USGS assessed one oil and two conventional gas plays and one basin-center gas play in Cretaceous/Jurassic Cotton Valley sandstones in the onshore northern Gulf of Mexico basin. Detailed evaluation of geologic and production data provides new insights into these Cotton Valley plays.

Two Cotton Valley sandstone trends are identified based on reservoir properties and gas-production characteristics. Transgressive blanket sandstones across northern Louisiana have relatively high porosity and permeability and do not require fracture stimulation to produce gas at commercial rates. South of this trend, and extending westward into east Texas, massive sandstones of the Cotton Valley exhibit low porosity and permeability and require fracture stimulation.

Pressure gradients throughout most of both trends are normal, which is not characteristic of basin center gas accumulations. Presence of gas-water contacts in at least seven fields across the blanket-sandstone trend together with relatively high permeabilities and high gas-production rates without fracture stimulation indicate that fields in this trend are conventional. Within the tight, massive-sandstone trend, however, permeability is sufficiently low that gas-water transition zones are vertically extensive and gas-water contacts poorly defined. With increasing depth through these transition zones, gas saturation decreases and water saturation increases until eventually gas saturations become sufficiently low that, in terms of cumulative production, wells become non-

commercial. Interpreted presence of gas-water contacts within the tight, massive Cotton Valley sandstone trend suggests that accumulations in this trend are also conventional, and that a basin center gas accumulation does not exist within the Cotton Valley Sandstone in the northern Gulf basin.

### **Is There a Basin-Center Gas Accumulation in the Ordovician-Age Glenwood Formation and St. Peter Sandstone, Central Michigan Basin ?**

Well data, structure maps, previous studies of abnormal pressures and thermal maturity, and published descriptions of gas fields were evaluated to determine if a basin-center gas accumulation might exist within the Ordovician-age Glenwood Formation and St. Peter Sandstone in the Michigan basin. The Glenwood-St. Peter section has several characteristics of typical basin-center gas accumulations, including thermally mature source rocks, low porosity sandstone reservoirs, extensive overpressure and extensive production of dry gas and condensate.

Well histories and data from more than 100 drill-stem tests reveal that many wells recovered significant volumes of salt water or gassy salt water with high chloride content (230,000 – 270,000 ppm Cl<sup>-</sup>) from the Glenwood-St. Peter interval. Pressure gradients range from 0.4 to 0.56 psi/ft, indicating normal pressures to moderate overpressures. Core descriptions indicate fair porosity (4 to 13 percent, average 9 percent) within the St. Peter Sandstone. Permeabilities vary widely, ranging from <0.1 md to 750 md, with 11 to 88 md in some thin sandstone lenses. High permeabilities are also indicated by the large amounts of water recovered in some of the drill-stem tests. Permeabilities as high as these are seldom found in typical basin-center gas accumulations.

The sixteen gas fields which produce from the Glenwood Formation and/or St. Peter Sandstone are all located within anticlinal structures. Most of these gas accumulations have distinct gas-water contacts, and many are flanked by abandoned wells which tested water from the Glenwood-St. Peter section in low structural positions. Some of the traps appear to be incompletely filled with gas. Significant water production and strong water drives have been noted in many of the published field descriptions. Reservoir temperatures are generally lower than 190° F. Reservoir pressure gradients range from near-normal (0.4 psi/ft) to moderately overpressured (0.56 psi/ft).

Regional structure maps indicate a relatively uncomplicated basin structure lacking major transverse fault zones or fault-bounded pressure compartments. The salt water system in the Glenwood-St. Peter interval probably extends throughout the central basin. Perhaps the Cambrian-Ordovician source rocks were not thick or rich enough and did not expel enough hydrocarbons to fully saturate the available porosity with gas, or perhaps they cooled down and ceased gas expulsion too early. The Glenwood-St. Peter section has not been completely saturated with gas. Based on analysis of well data and field descriptions, the Glenwood-St. Peter gas system is not a basin-center gas accumulation.

### **Potential for a Basin-Center Gas Accumulation in the Raton Basin, Colorado and New Mexico**

The Raton Basin appears to contain a significant continuous or basin-center type gas accumulation in sandstones of the Upper Cretaceous Trinidad Sandstone and Vermejo Formation and Upper Cretaceous and Paleocene Raton Formation. The accumulation is underpressured and occurs at comparatively shallow (< 3,500 ft) depths. The sandstones are interbedded with coal beds that are currently being developed for coalbed methane, and the coals are the likely source for gas found in the sandstones. Based on analog comparisons with other Rocky Mountain basins, relatively water-free production should occur where levels of thermal maturity in the coals exceed a

vitrinite reflectance value of 1.1 percent. This level of thermal maturity occurs over much of the central part of the Raton Basin. Because of the shallow depths, some of the accumulation has probably been degraded by surface water invasion.

### **Does the Forbes Formation in the Sacramento Basin Contain a Basin-Center Gas Accumulation?**

Well data, structural cross sections and published studies of abnormal pressures, methane isotopes, vitrinite reflectance measurements and thermal maturity were evaluated to determine if a basin-center gas accumulation might exist within the Cretaceous-age Forbes Formation in the Sacramento Basin, California. The Forbes Formation is a mud-rich turbidite system with thick marine shale deposits and discontinuous sandstone lenses. At least twenty-seven natural gas fields have been discovered in the Forbes Formation, mainly in traditional structural and stratigraphic traps with distinct gas-water contacts.

Previous studies of source rock and organic content show that the Forbes Formation contains low levels of gas-prone organic material, mainly dispersed fragments of lignite, wood and land plants. A recent study of the Dobbins Shale notes extensive bioturbation and lack of laminations, indicating oxidizing conditions. Studies of source rock quality in outcrops along the western flank of the basin found low organic content throughout the Upper Cretaceous section. Thermal gradients and bottom hole temperatures are unusually low in the Sacramento Basin. Published vitrinite reflectance profiles show that the Forbes is immature to sub-mature throughout most of the basin. All Forbes gas production comes from thermally immature sandstone reservoirs with low temperatures ( $< 190^{\circ}\text{F}$ ) and relatively high porosities (17 – 30 percent). The gas produced from most Forbes reservoirs is primarily methane, with variable amounts of nitrogen. Isotope analyses indicate that the methane is a mixture of immature, biogenic methane and overmature, thermogenic methane, which apparently migrated long distances from a deep gas kitchen, probably dissolved in formation waters under high pressure.

The lower Forbes Formation and underlying Dobbins Shale are overpressured throughout the central and southern parts of the basin. Drill stem test data from the Grimes, Buckeye, Kirk, and Arbuckle Gas Fields and the Rumsey Hills area indicate abnormal pressure gradients ranging from 0.5 to 0.92 psi/ft in the Forbes. The overpressuring fluid is usually gassy salt water, not hydrocarbons. No evidence of sub-normal pressure was observed. Previous authors have suggested that the primary causes of the overpressures in the Forbes are tectonic compression and aquathermal pressuring, rather than hydrocarbon generation. The Forbes appears to be regionally water-saturated, except for localized structural/stratigraphic gas traps. The Forbes has not been extensively de-watered by local gas generation. The basin-center gas model does not appear to fit the Forbes Formation in the central, northern and eastern parts of the Sacramento Basin.

Previous authors have suggested that the Delta Depocenter, a deep wrench basin in the southwestern Sacramento Basin, may be the deep gas kitchen where much of the basin's gas was generated. Structural cross sections show that the lower Forbes Formation and Dobbins Shale may be buried 18,000 to 20,000 ft deep in this structural depression. Older source rocks such as the Upper Cretaceous-age Funks and Yolo Shales may be buried as deep as 23,000 to 26,000 ft. A thermal maturity model was constructed for the Delta Depocenter, using Basin-Mod software, published cross sections, vitrinite profiles, thermal gradients and well log data. The maturity model predicts a deep gas generation window with  $R_o > 0.9$  percent at 15,000 ft and  $R_o > 3.0$  percent at approximately 26,000 ft. The lower Forbes, Dobbins, Funks and Yolo shales are probably within the gas generation window. If these source rocks are rich enough to generate large quantities of gas, a basin-center gas system might exist in the deepest parts of the Delta Depocenter. Several exploration wells have been drilled to 14,000 to 15,059 ft in this area. Well histories, well logs and drill stem test results were reviewed for evidence of basin-center gas conditions near total depth. High drilling-mud densities indicate overpressures, but high-pressure salt water was recovered in several formation tests; evidently, the Forbes Formation is still water-saturated at this depth. The formation test data do not indicate basin-center gas conditions in the 14,000 to 15,000 ft depth range.

An ultra-deep basin-center gas system might exist below 16,000 ft in the Delta Depocenter, if gas expelled from mature source rocks has extensively saturated and de-watered the reservoirs. However, the complex Midland and Kirby Hills Fault zones may provide permeable migration paths for gas to escape from this deep gas kitchen. The gas kitchen may have been breached by faulting, and thus failed to become a continuous, basin-center gas accumulation. There have not yet been any wells drilled deep enough to evaluate this gas kitchen. The possibility of a basin-center gas accumulation in the Delta Depocenter should be considered highly speculative.

### **Is There a Basin-Center Gas Accumulation in the Travis Peak (Hosston) Formation, Gulf Coast Basin, USA?**

Potential of Lower Cretaceous Travis Peak sandstones in the northern Gulf Coast Basin to harbor a basin-center gas accumulation was evaluated by examining (1) depositional/diagenetic history and reservoir properties of Travis Peak sandstones, (2) presence and quality of source rocks for generating gas, (3) burial/thermal history of source rocks and time of gas generation/migration relative to tectonic development of Travis Peak traps, (4) gas and water recoveries from drillstem and formation tests, (5) distribution of abnormal pressures based on shut-in-pressure data, and (6) presence or absence of gas-water contacts associated with gas accumulations in Travis Peak sandstones.

The Travis Peak Formation is a basinward-thickening wedge of terrigenous clastic sedimentary rocks that underlies the northern Gulf of Mexico Basin from east Texas across northern Louisiana to southern Mississippi. Clastic influx was focused in two main fluvial-deltaic depocenters located in northeast Texas and southeast Mississippi/northeast Louisiana. Across the main hydrocarbon-productive trend in east Texas and north Louisiana, the Travis Peak Formation is about 2,000 ft thick. In east Texas, stacked, fluvial-channel sandstones comprise the bulk of the formation. Channel sandstones grade upward from braided to meandering, and are capped by a thin sequence of coastal-plain, paralic, and marine strata reflecting the overall transgression and relative rise in sea level that occurred during Travis Peak deposition. In north Louisiana, sandstones deposited in interdeltic settings are separated by thicker shale intervals.

Most Travis Peak hydrocarbon production in east Texas comes from drilling depths between 6,000 and 10,000 ft. Significant decrease in porosity and permeability through that depth interval results primarily from increasing amounts of quartz cement with depth. Reservoir properties of many Travis Peak sandstones, however, are significantly better than those characteristic of basin-center gas reservoirs in which inherent, ubiquitous, low-permeability provides an internal, leaky seal for thermally generated gas. Above 8,000 feet in east Texas, Travis Peak sandstone matrix permeabilities often are significantly higher than the 0.1 md cutoff that characterizes tight-gas reservoirs. Below 8,000 ft, matrix permeability of Travis Peak sandstones is low because of pervasive quartz cementation, but abundant natural fractures impart significant fracture permeability. In east Texas, oil and gas seem to be concentrated in meandering-channel and paralic sandstones in the upper 300 ft of the Travis Peak. This probably occurs because these sandstones are encased in thick shales that provide effective seals. The underlying thick fluvial sequence lacks widespread shale barriers, and stacked, braided-channel sandstones provide an effective upward migration pathway for gas. In north Louisiana, relatively thick shales throughout the Travis Peak provide effective seals for interdeltic sandstones.

Because of significant variation with depth in both reservoir properties and occurrence of shale seals in the Travis Peak Formation in east Texas, inaccurate interpretations can be made by using pressure data or presence of hydrocarbon-water contacts at a particular depth to characterize the entire Travis Peak at a given well location. Although pressure data within the middle and lower Travis Peak Formation are limited in east Texas, significant overpressure caused by thermal generation of gas, which is typical of basin-center gas accumulations, is not common within the Travis Peak. Significant overpressure was found in only one Travis Peak sandstone reservoir in one of 24 oil and gas fields examined across east Texas and north Louisiana. Presence of a gas-water contact perhaps is the most definitive criterion indicating that a gas accumulation is conventional rather than a "sweetspot" within a basin-center gas accumulation. Hydrocarbon-water contacts within Travis Peak sandstone

reservoirs were documented in 17 fields, and probably occur in considerably more fields, across the productive Travis Peak trend in east Texas and north Louisiana. All known hydrocarbon-water contacts in Travis Peak reservoirs in east Texas, however, occur within sandstones in the upper 500 ft of the formation. Widespread presence of hydrocarbon-water contacts indicates lack of significant basin-center gas accumulations within the Travis Peak Formation throughout north Louisiana, and within the upper 500 ft of the Travis Peak in east Texas. Although no gas-water contacts have been reported within the lower three-fourths of the Travis Peak Formation in northeast Texas, gas production from that interval is limited. Best available data suggest that most middle and lower Travis Peak sandstones are water-bearing in northeast Texas. These data together with absence of significant overpressure suggest that the middle and lower Travis Peak section also lacks significant basin-center gas in northeast Texas.

Insufficient hydrocarbon charge relative to permeability of Travis Peak reservoirs might be primarily responsible for lack of overpressure and basin-center gas within the Travis Peak Formation. Shales interbedded with Travis Peak sandstones in east Texas are primarily oxidized floodplain deposits with insufficient organic-carbon content to be significant sources of oil and gas. Most likely sources for hydrocarbons in Travis Peak reservoirs are two stratigraphically lower units, Jurassic-age Bossier Shale of the Cotton Valley Group, and laminated, lime mudstones of the Jurassic Smackover Formation. Hydrocarbon charge, therefore, might be sufficient for development of conventional gas accumulations but insufficient for development of basin-center gas as a result of the absence of proximal source rocks and effective migration pathways from stratigraphically or geographically distant source rocks. Additionally, relatively high matrix and fracture permeability through significant portions of Travis Peak sandstone reservoirs might allow upward migration of gas to the degree that abnormally high pressure and basin-center gas cannot develop.